ORIGINAL

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MEMORANDUM

TO: Docket Control

FROM: Elijah O. Abinah
Director
Utilities Division

DATE: April 1, 2022

RE: IN THE MATTER OF THE FUEL AND PURCHASED POWER PROCUREMENT AUDIT FOR ARIZONA PUBLIC SERVICE COMPANY (DOCKET NO. E-01345A-21-0056)

At the March 23 and 24, 2021, Open Meeting, the Arizona Corporation Commission ("Commission") directed Staff to open a new docket for the purpose of conducting an audit of Arizona Public Service Company's ("APS") fuel and purchased power procurement practices. On March 29, 2021, Staff filed a memo requesting a new docket be opened. Attached is the Report on the Fuel and Purchased Power Audit for APS prepared by Larkin & Associates PLLC and Energy Ventures Analysis on behalf of the Arizona Corporation Commission Utilities Division.

EOA:CLA:/

Originator: Candrea Allen

Attachments

ACC - Docket Control - Received 4/1/2022 11:05 AM
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ATTACHMENT

REPORT ON THE FUEL AND PURCHASED POWER AUDIT OF ARIZONA PUBLIC SERVICE COMPANY

(Docket No. E-01345A-21-0056)

March 31, 2022

Prepared for:
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1 INTRODUCTION

The Staff of the Arizona Corporation Commission ("Staff") solicited proposals for an auditor to analyze, interpret, and making specific recommendations with respect to the structure, policies and procedures of Arizona Public Service Company's ("APS") power purchases, fuel procurement and utilization and related functions. The audit includes an examination of all operational and managerial aspects of the fuel management practices and APS's portfolio of fuel and purchased power contracts as well as the monthly filings associated with APS's Power Supply Adjustor ("PSA") mechanism.

Following a competitive solicitation, Larkin & Associates PLLC ("Larkin") and its subcontractor, Energy Ventures Analysis, Inc. ("EVA") (together "Audit Team") were selected by the Arizona Staff to perform the regulatory audit of APS's fuel and purchased power procurement and related functions. The audit covers the period 2019, 2020 and January 2021.

Audit Approach

Larkin and EVA conducted this audit through a combination of document review, interrogatories, site visits and interviews. Larkin and EVA visited the Cholla Power Plant on August 24, 2021 and the Four Corners Power Plant on August 25, 2021. Larkin and EVA conducted interviews covering the subjects listed in Exhibit 1-2 below:

Exhibit 1-1.
List of Interviews

Date	Subject
6/21/2021	Fuel Audit kickoff call with APS
7/29/2021	Coal Procurement at Cholla and Four Corners
8/19/2021	Logistics Meeting with APS regarding on-site visits to Cholla and Four Corners
8/24/2021	Interview Plant Manager and other APS personnel at the Cholla Plant
8/25/2021	Interview Plant Manager and other APS personnel at the Four Corners Plant
10/29/2021	APS walkthrough of the PSA filings and related confidential PSA workpapers
11/12/2021	APS walkthrough of its forecasting simulation models (RTSim and Aurora)

Audit Findings

For the period of January 2019 through January 2021, APS had the following costs in its PSA:

Exhibit 1-2.
Summary of Net Native Load Fuel and Purchased Power Expense for Audit Period January 2019 through January 2021

Line No.	Description	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019
1	Gas Generation Fuel Expense	$ 21,421,097	$ 17,615,689	$ 16,162,464	$ 10,568,312	$ 10,454,915	$ 15,108,243	$ 21,648,530	$ 23,414,388	$ 20,674,687	$ 18,408,223	$ 13,549,671	$ 22,081,525
2	Gas Generation Fuel Expense under Tolling Arrangements	$ -	$ -	$ -	$ -	$ 1,918,364	$ 2,972,305	$ 3,904,897	$ 3,813,978	$ 3,888,100	$ 3,228,415	$ (1,974)	$ (81,003)
3	Gas Hedges and Mark-to-Market Expense	$ (11,564,508)	$ (5,579,686)	$ 5,352,526	$ 7,928,177	$ 11,687,444	$ 14,198,786	$ 6,736,960	$ 12,618,344	$ 3,503,481	$ (10,262,269)	$ 8,735,922	$ 14,206,872
4	Oil Generation Fuel Expense	$ 56,819	$ 59,204	$ 106,819	$ 166,629	$ 94,353	$ 42,289	$ 90,016	$ 120,989	$ 36,699	$ 63,560	$ 19,785	$ 32,545
5	Coal Generation Fuel Expense	$ 22,514,610	$ 22,556,786	$ 12,328,091	$ 21,492,708	$ 18,064,455	$ 23,256,477	$ 28,429,613	$ 31,479,607	$ 25,347,504	$ 21,395,382	$ 19,344,096	$ 23,755,382
6	Nuclear Generation Fuel Expense	$ 6,084,893	$ 5,432,648	$ 6,069,283	$ 4,018,255	$ 5,532,079	$ 5,940,639	$ 6,159,376	$ 5,857,234	$ 5,641,328	$ 4,247,658	$ 5,868,817	$ 6,299,962
7	Owned Renewable Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Subtotal Generation Fuel Expense (Sum Line 1-7)	$ 38,512,911	$ 40,084,642	$ 40,019,182	$ 44,174,081	$ 47,751,610	$ 61,518,739	$ 66,969,392	$ 77,304,541	$ 59,091,800	$ 37,080,969	$ 47,516,317	$ 66,295,283
9	Long-Term Purchased Power Expense	$ 12,530,154	$ 14,571,807	$ 18,995,520	$ 22,445,741	$ 33,248,430	$ 36,360,691	$ 31,605,260	$ 32,354,931	$ 30,056,766	$ 31,676,444	$ 12,959,448	$ 12,241,733
10	Market Purchased Power Expense	$ 5,309,024	$ 5,787,343	$ 7,421,724	$ 12,490,956	$ (2,073,838)	$ 9,883,854	$ 23,368,372	$ 28,153,912	$ 16,683,225	$ 4,931,113	$ 15,432,908	$ 11,905,650
11	Other Purchased Power Expense	$ (38,495)	$ (528,040)	$ 6,161,516	$ 2,416,587	$ 11,052,070	$ 12,020,227	$ 7,309,362	$ 998,876	$ 529,739	$ 1,639,641	$ (959,906)	$ (418,244)
12	Total System Fuel and Purchase Power Expense (Sum Lines 8-11)	$ 56,313,594	$ 59,915,752	$ 72,597,942	$ 81,527,365	$ 89,978,272	$ 119,783,510	$ 129,252,385	$ 138,812,260	$ 106,361,531	$ 75,328,167	$ 74,948,766	$ 90,024,422
13	Revenue from System Excess Sales	$ (4,581,028)	$ (17,038,296)	$ (13,709,195)	$ (2,464,998)	$ (898,913)	$ (7,243,627)	$ (11,546,552)	$ (10,821,936)	$ (13,459,689)	$ (12,225,806)	$ (5,970,039)	$ (10,926,824)
14	Net Native Load Fuel and Purchased Power Expense (Line 12 + Line 13)	$ 51,732,567	$ 42,877,456	$ 58,888,747	$ 79,062,368	$ 89,079,359	$ 112,539,884	$ 117,705,833	$ 127,990,324	$ 92,901,842	$ 63,102,361	$ 68,978,727	$ 79,097,598

Line No.	Description	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	January 2021
15	Gas Generation Fuel Expense	$ 18,474,545	$ 13,864,925	$ 9,870,958	$ 13,052,788	$ 20,536,194	$ 19,628,038	$ 24,223,587	$ 27,255,166	$ 23,828,648	$ 20,812,834	$ 23,208,562	$ 22,880,806	$ 21,347,618
16	Gas Generation Fuel Expense under Tolling Arrangements	$ -	$ -	$ -	$ -	$ -	$ 4,457,146	$ 6,337,078	$ 7,114,854	$ 7,362,739	$ (45,450)	$ (54,653)	$ -	$ -
17	Gas Hedges and Mark-to-Market Expense	$ 23,769,277	$ 16,249,271	$ (15,005,536)	$ (39,539,704)	$ 24,176,120	$ 17,690,845	$ (18,272,446)	$ (39,139,060)	$ 9,922,043	$ (37,986,324)	$ 34,801,808	$ 20,682,486	$ (13,327,674)
18	Oil Generation Fuel Expense	$ 17,226	$ 5,240	$ 19,932	$ 113,497	$ 165,503	$ 37,186	$ 172,455	$ 161,747	$ 253,113	$ 229,325	$ 110,574	$ 82,138	$ 34,120
19	Coal Generation Fuel Expense	$ 22,990,511	$ 16,564,979	$ 13,785,540	$ 11,899,340	$ 13,364,816	$ 18,277,797	$ 25,802,934	$ 23,523,289	$ 24,312,293	$ 16,806,318	$ 10,807,149	$ 18,491,284	$ 20,595,244
20	Nuclear Generation Fuel Expense	$ 6,300,381	$ 5,330,295	$ 5,946,541	$ 4,265,743	$ 5,794,002	$ 5,944,903	$ 6,159,650	$ 6,210,497	$ 5,996,539	$ 4,501,199	$ 3,657,090	$ 5,704,969	$ 6,015,184
21	Owned Renewable Generation	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	Subtotal Generation Fuel Expense (Sum Line 15-21)	$ 71,551,941	$ 52,014,709	$ 14,617,435	$ (10,208,336)	$ 64,036,635	$ 66,035,915	$ 44,423,259	$ 25,126,493	$ 71,675,375	$ 4,317,903	$ 72,530,531	$ 67,841,684	$ 34,664,493
23	Long-Term Purchased Power Expense	$ 15,206,133	$ 17,874,626	$ 18,646,745	$ 24,079,138	$ 25,776,932	$ 44,406,714	$ 41,214,777	$ 42,507,186	$ 39,691,825	$ 18,522,786	$ 15,883,140	$ 14,490,984	$ 14,760,051
24	Market Purchased Power Expense	$ 2,811,954	$ 5,093,256	$ 3,427,166	$ 5,091,394	$ 6,233,151	$ 7,394,983	$ 15,664,228	$ 38,119,660	$ 7,581,663	$ 24,475,407	$ 15,404,405	$ 12,060,586	$ 4,068,939
25	Other Purchased Power Expense	$ 2,679,368	$ (967,756)	$ 4,181,506	$ 3,414,447	$ 7,261,349	$ 7,467,709	$ 5,991,210	$ 1,146,401	$ 13,438,201	$ 448,223	$ 20,595	$ 950,519	$ (2,815,416)
26	Total System Fuel and Purchase Power Expense (Sum Lines 22-25)	$ 92,249,395	$ 74,014,835	$ 40,872,851	$ 22,376,643	$ 103,308,067	$ 125,305,321	$ 107,293,473	$ 106,899,740	$ 132,387,064	$ 47,764,319	$ 103,838,671	$ 95,343,773	$ 50,678,067
27	Revenue from System Excess Sales	$ (3,176,997)	$ (4,630,442)	$ (4,157,329)	$ (4,916,746)	$ (3,163,022)	$ (8,974,470)	$ (7,160,280)	$ (20,673,486)	$ (19,885,784)	$ (6,837,658)	$ (6,066,730)	$ (3,169,607)	$ (4,107,006)
28	Net Native Load Fuel and Purchased Power Expense (Line 26 + Line 27)	$ 89,072,398	$ 69,384,393	$ 36,715,523	$ 17,459,897	$ 100,145,045	$ 116,330,851	$ 100,133,194	$ 86,226,254	$ 112,501,280	$ 40,926,661	$ 97,771,941	$ 92,174,166	$ 46,571,062

Source: Staff Data Request 1.95 - Confidential PSA Workpapers Summary

The above exhibit[1] breaks out the Company's fuel expense by (1) gas generation, (2) gas generation under tolling agreements, (3) gas hedges and mark-to-market, (4) oil generation (including oil burned at non-oil generating stations), (5) coal generation, nuclear generation and owned renewable generation (none recorded during the review period). In addition, APS breaks out purchased power expense by (1) long-term purchased power, (2) market purchased power, and (3) other purchased power expense. The source of the information is the Company confidential PSA workpapers. The combination of all sources of fuel and purchased power expense results in total system fuel and purchased power expense as shown on line 12 for 2019 and line 26 for 2020 and January 2021. Finally, as shown on lines 13 (for 2019) and 27 (for 2020 and January 2021), fuel and purchased power expense is reduced by revenue from system excess sales (i.e., off-system sales) to arrive at the net native load fuel and purchased power expense shown on line 14 for 2019 and line 28 for 2020 and January 2021.

This audit report contains the following findings for the audit period of calendar years 2019 and 2020 and January 2021:

1. There were significant modifications to the Cholla and Four Corners coal supply agreements prior to the audit period, as discussed in detail in Chapter 3. The prior APS fuel audits did not include prudence reviews of those pre-2019 coal contract agreement modifications even though there were significant associated costs. The Audit Team believes that prudence reviews should be conducted on a timely basis as the determination of prudence is tied to the information available at the time of the commitment, not subsequent thereto. APS indicated it did not believe that such prudence reviews were mandated. As indicated in the recommendations, on page 1-16, we recommend that all future APS fuel and purchased power audits should include a prudence review of all major fuel-related agreements including commodity and transportation.
2. The transition away from coal is underway. The remaining two units (1 and 3) at the Cholla Plant are scheduled to close in 2025. The remaining two units at the Four Corners plant (4 and 5) are expected to be closed in 2031 with seasonal operation of Unit 5 to start in 2023.[2] A number of utilities have found that planned replacement capacity has been delayed due to COVID and supply chain considerations. As a result, there may be benefits in terms of system reliability for maintaining flexibility on the scheduled retirement dates.
3. The dispatch of the coal plants has been challenged by renewables and natural gas. Unlike coal, natural gas pricing generally floats with the commodity price resulting in significant volatility. In order to handle this volatility, APS has a formal hedging program that seeks to manage natural gas price volatility.
4. Stress in the energy markets subsequent to the audit period demonstrated the consequences of significant reliance on natural gas for future generation with the more

[1] Note about material in this report that is referenced to data responses and workpapers that were marked by APS as "confidential": APS was provided an opportunity to review such material in the report for whether it could be publicly disclosed or required confidential redaction treatment. APS indicated that the information in Exhibit 1-2 can be publicly disclosed. The redactions contained in the remainder of the report reflect the redactions that APS indicated were necessary for APS-designated confidential material.

[2] See additional discussion in Chapter 3.

than doubling of the reported delivered price of natural gas. Even with the natural gas price hedging program, there will be a significant increase in power pricing as natural gas generation accounts for over 25 percent of APS generation.

5. APS was a joint owner and operator (except where noted) of five power plants during the review period, including: (1) Cholla Power Plant; (2) Four Corners Power Plant; (3) Navajo Generating Station (closed in 2019 and was operated by Salt River Project ("SRP")); (4) Palo Verde Nuclear Plant; and (5) Yucca Power Plant. The fuel costs at the jointly-owned generation plants are shared by the plant owners in accordance with the contractual agreements of the plant owners and by the amount of fuel used. During the review period, the fuel costs at the jointly-owned plants were allocated to the co-owners in accordance with the contractual agreements.

6. With regard to the coal-fired plants that generated power for APS during the review period, the Company's rights to access information to review plant operation performance and related costs are summarized as follows: (1) Cholla Plant – APS is a partial owner, but operates the Cholla Plant so the Company has full access to operational performance and related costs; (2) Four Corners Plant – APS is a 63 percent owner, and operates the Four Corners Plant so the Company has full access to operational performance and related costs; and (3) Navajo Generating Station – APS was a partial owner, but SRP operated the Navajo Generating Station until it closed near the end of 2019. Upon request, APS had full access to operational performance and related costs.

7. As it relates to APS's procedures for accounting for fuel receipts, testing of samples to ensure quality, and payments to vendors, we reviewed three voluminous confidential attachments related to APS's fuel purchasing and inventory accounting process, including Coal Settlements Procedures (144 pages), Gas Storage Accounting Procedures (20 pages), and Gas Settlements Procedures (92 pages). Based on our review of these documents, we conclude that APS's processes for testing fuel purchases for quality and approving payments to fuel suppliers are comprehensive and appropriate. See Chapter 4 for a more detailed discussion related to these three areas.

8. The Company has procedures in place for preparing monthly fuel cost and analysis reports. The Company's objectives for its monthly fuel analysis are to (1) identify factors that impact dispatch and generation decisions, and (2) to compare the result with the Company's pre-existing budget. Specific procedures include: (1) a Fuel Variance Report that tracks the monthly variance between actuals and budget; it contains accounting data (from financial reporting and back-office accounting) and unit generation data from energy accounting whereby the detailed breakdown matches the Company's monthly Gross Margin Statement, and (2) A Fuel Variance Table that is built based on hourly data through an analytical model to identify and calculate several factors that impact actual results as compared to budget. It provides more detailed dispatch analysis based on volume (load), price, outage/replacement power and other factors. It also shows how the Company utilizes resources during unit outage events. We find that these APS procedures are detailed and appropriate.

9. APS's monthly fuel analysis reporting is done on three separate reports including: (1) a report titled APS Fuel & Purchased Power Summary Native Load and Excess Sales Fuel Cost Details, (2) a two-page report with Energy Variance Explanations (GWH) and Fuel

Cost Variance Explanations, and (3) a report titled Fuel and Purchase Power Key Stories. These reports are discussed in more detail in Chapter 4. We find that APS's fuel analysis reporting for the audit period is appropriate.

10. The Company's PSA-related deferrals are broken out by fuel deferrals and Operations & Maintenance ("O&M") deferrals. For calendar year 2019, the Company reflected fuel expense deferrals totaling ($94.174 million), amortization of deferred fuel recovery totaling $50.523 million for a total net fuel deferral liability of ($43.651 million). As it relates to O&M deferrals in 2019, the Company reflected chemical expense deferrals totaling ($1.886 million), emission allowance deferrals totaling ($28,000) and amortization of deferred O&M refunds totaling ($563,000) for a total net O&M deferral liability of ($2.478 million). Based on our review and selective testing of APS's accounting records and audit trail documentation for the audit period, we find that these amounts are reasonable and reflect costs that were prudently incurred and consistent with the categories of PSA includable costs.

11. For calendar year 2020, the Company reflected fuel expense deferrals totaling ($33.198 million), amortization of deferred fuel recovery totaling ($15.615 million) for a total net fuel deferral liability of ($48.813 million). As it relates to O&M deferrals in 2020, the Company reflected chemical expense deferrals totaling ($26,000), emission allowance deferrals totaling ($29,000) and amortization of deferred O&M refunds totaling $3.568 million for a total net O&M deferral of $3.512 million. For January 2021, the Company reflected fuel expense deferrals of $18.928 million, amortization of deferred fuel recovery of ($1.153 million) for a total net fuel deferral of $17.775 million. As it relates to O&M deferrals in January 2021, the Company reflected a chemical expense deferral of ($19,000), emission allowance deferrals totaling ($2,000) and amortization of deferred O&M refunds totaling $242,000 for a total net O&M deferral of $221,000. The Company does not record fuel cost deferrals by individual line item or account. Rather, APS defers expenses that differ from those included in the base cost of fuel and purchased power in accordance with the PSA Plan of Administration ("POA"), which at page 6 states: "An amount generally expressed as a rate per kWh[3], which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. 76295 set the base cost at $0.030168 per kWh effective on August 19, 2017." We find that APS's procedures for recording fuel cost deferrals are reasonable and consistent with the provisions concerning such deferrals in the PSA.

12. The Company identified the following two system simulation models that it uses for forecasting fuel and purchased power volumes and the associated expenses: The Real Time Simulation (RTSim) model (developed by Simtec) is used by APS's Marketing & Trading Business Support and develops forecasts based on a mid-range focus (i.e., 1 to 5 years). In addition, APS also uses the Aurora model (developed by Energy Exemplar) for Resource Planning and Analysis. The Aurora model develops forecasts based on a long-term focus (i.e., 6 to 20 years). The RTSim model is comprised of the following eight modules: (1) Market (power prices, purchase and sales transactions and solar PPA

[3] kWh = kilowatt hour

contracts), (2) Fuel (natural gas prices and fuel contracts), (3) Run (loads and reserve requirements), (4) Outage (planned outages), (5) Hydro Module (wind resources, APS-owned solar and battery storage), (6) Emissions, (7) Unit (Capacities and Operating Assumptions), and (8) Schedule Module (seasonal capacities, annual pricing & forced outage rates and heat rates I/O schedules). The RTSim model inputs include: (1) forward price calculation, (2) monthly fuel prices, (3) outage schedule process (planned and maintenance), (4) renewable generation modules, and (5) GMIS Power Manager. While the inputs of the Aurora model are similar to that of the RTSim model, the Aurora model does not track fixed and variable costs and develops forecasts with a focus on the long term (6 to 20 years). APS uses the Aurora model for forecasting over longer time frames (i.e., such as for integrated resource planning).

13. The average number of RTSim model updates is three to six times per year and the average number of production assumption updates is 20 to 25 times per year.

14. Day-ahead planning affects system dispatch decisions as well as short-term energy transactions, such as those in the Energy Imbalance Market ("EIM"). The models used by day-ahead traders and for the correct dispatch of generating resources at APS is Power Costs, Inc. ("PCI"), which provides a system optimization solution that is used by Marketing & Trading business support, day-ahead and real-time traders. We reviewed APS's 19-page document titled "Procedure: PCI Optimization and Base Schedule Submission", which is the PCI system optimization solution. We conclude that APS's day-ahead planning and system dispatch procedures were reasonable during the audit period.

15. APS considers weather and the availability and generation from renewable resources (e.g., solar) when determining the correct dispatch of generating resources. The Company evaluates the effectiveness of its short-term modeling and forecasting (i.e., such as days during summer, shoulder periods, and winter) versus actual results by: (1) reviewing monthly budget fuel variances, which includes variances driven by outages, market and gas prices, load deviations and replacement costs, (2) tracking monthly metrics that compare Day-Ahead ("DA") renewable and load forecasts to actual performance, (3) Generation, Marketing and Trading meeting on a monthly basis to discuss unit operating parameters which are dynamically managed through the different seasons, (4) tracking all deviations in unit performance and comparing the unit operating targets to actual megawatt ("MW") generation output, and (5) tracking balance targets for each hour to ensure reliability of the system to each operating hour as well as overall flexibility of the system from hour to hour. APS follows a continuous improvement philosophy for implementing any changes to its system dispatch model in the following categories: improving natural gas forecasting and gas management accuracy; improving the accuracy of load forecasting; adding automation to improve operational efficiency and reduce human performance mistakes; and improving interactions with external markets. We find that these APS modeling review and dispatching procedures have been reasonable during the audit period.

16. We compared APS's off-system sales during the review period to the relevant pages for Sales for Resale from its 2019 and 2020 FERC Form 1 filings as well as to a confidential attachment showing its off-system sales for January 2021. The amounts for off-system

sales in the Company's 2019 and 2020 FERC Form 1 filings did not tie directly to the revenue from system excess sales reflected in the Company's confidential PSA workpapers because FERC Form 1 Sales for Resale includes all charges appropriately charged to FERC Account 447, but the PSA POA only allows for the revenue recorded from sales made to non-native load customers for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power. In addition, other power and gas system sales recorded in FERC Account 456 are included in the PSA monthly filings as Revenue from System Excess Sales and are not reported in FERC Form 1 Sales for Resale. We reviewed the APS provided reconciliations of the off-system sales listed in the 2019 and 2020 FERC Form 1 filings and confidential attachment ExcelAPS21FA00085 (for January 2021) to the monthly amounts for Revenue from System Excess Sales from the confidential monthly PSA workpapers. No exceptions were noted.

17. We reviewed the types of off-system sales (e.g., contractual off-system sales, short-term, day ahead, etc.) that are reflected in the PSA filings for each month of the review period, including: daily, hourly, intrahour, and long-term, all of which total the system excess revenues by market. Combining the total system excess revenues by market with the other system excess revenues totaled the amounts included in APS's confidential monthly PSA workpapers. No exceptions were noted.

18. We reviewed the margins that were realized on the off-system sales that are reflected in the PSA filings for each month of the review period. The Revenue and Expense amounts were broken out by FERC account. We tied these amounts back to the "Offsystem Margins" tab in APS's monthly confidential PSA workpapers and to the public PSA filings. No exceptions were noted.

19. APS participates in the California Independent System Operator's ("CAISO") EIM, which is a real-time energy market in the western United States.

20. We reviewed APS's monthly EIM market purchases, EIM sales and EIM cost savings for each month of the review period. The margins for EIM cost savings for system excess sales totaled $22.654 million for calendar 2019, $16.988 million for calendar 2020 and $347,660 for January 2021. According to the Company's response to Staff data request 7.5, the EIM sales margins were calculated based on sales of energy (i.e., netting energy revenue against allocated EIM transactions costs) and reflect the fuel and purchase power revenue and expense accounts that are authorized to be recovered through the PSA. We tied the monthly amounts that total the 2019, 2020, and January 2021 margins for EIM cost savings for system excess sales noted above to APS's confidential monthly PSA workpapers. No exceptions were noted.

21. According to a CAISO Benefits Study conducted in the first quarter of 2021, APS had EIM-related benefits totaling $54.48 million in 2019, $48.96 million in 2020 and $15.01 million through the first quarter of 2021. These EIM benefits represent both incremental off-system sales margins as well as reduced fuel costs due to the economic optimization across the EIM footprint.

22. APS entered 2019 with three utility-scale storage projects with a combined capacity of 6 MW/12 MWh. One of APS's utility-scale energy storage projects, the McMicken energy

storage battery facility, experienced a catastrophic equipment failure in April 2019. As a result of this failure, APS took the other two utility-scale systems offline, both of which remained inactive until January 2021. The incident at the McMicken facility prompted investigations to determine the cause. In July 2020, the Company reported the findings of its investigation to the Commission and is applying what it learned from the investigation to integrate proper engineering as well as design and safety features towards future energy storage sites. The Company did not incur battery storage costs or other electric storage costs nor did APS purchase or install utility-scale battery storage during the 2019, 2020 and January 2021 review period. Costs related to the McMicken energy storage facility were removed from APS's cost of service in the APS rate case (Docket No. E-01345A-19-0236).

23. Larkin selected three months in the review period for a detailed testing of fuel costs, by reviewing copies of invoices and related payment documentation for fuel purchases recorded in August 2019, August 2020 and January 2021. Larkin first examined each invoice and compared the vendor name, invoice number and invoice date to the accompanying voucher and supporting detail. The invoice detail broke out the purchases by ship date, description, outbound ID number, number of transport units, quantity, unit of measure, currency, price/unit of measure ("UOM") and amount. We then traced the total of the amounts listed for Cholla and Four Corners from the supporting detail to the invoices. No exceptions were noted.

24. Larkin tested coal delivery costs by obtaining and reviewing copies of freight cash vouchers for two days of coal receipts in August 2019, August 2020 and January 2021 as well as copies of the portions of the corresponding coal received reports, which the Company provided for Cholla. As it relates to Four Corners and the Navajo Generating Station, since both of those generating facilities are mine mouth power plants, there are no freight vouchers. Upon reviewing the documentation for Cholla, Larkin verified the freight costs reflected on the Burlington Northern Santa Fe ("BNSF") Railway freight bills tied to the corresponding invoices. In addition, Larkin tied out the amounts reflected on the invoices and freight bills to the APS check request documents. No exceptions were noted.

25. Larkin reviewed the Company's procedures for coal sampling, including (1) the frequency of coal sampling, (2) how the coal samples are identified, and (3) what control is exercised over forwarding coal samples to the laboratory. As it relates to the Company's procedures for preparing monthly fuel analysis reports, for both Cholla and Four Corners, Larkin reviewed the sampling, analysis and fuel reports, which are provided to APS by an independently-operated Coal Sampling and Analysis Provider ("CSASP"), SGS Mineral Services, (SGS North America Inc.). Three separate reports we reviewed, including: (1) APS Fuel & Purchased Power Summary Native Load and Excess Sales Fuel Cost Details; (2) Energy Variance Explanations (GWH) and Fuel Cost Variance Explanations; and (3) Fuel and Purchase Power Key Stories. Larkin reviewed these reports, which are discussed in more detail in Chapter 4, and found them to be thorough and comprehensive documentation relative to the Company's monthly coal sampling and analysis procedures.

26. There were no pending or approved retroactive escalations affecting fuel costs during the review period.

27. Larkin conducted on-site plant visits to the Company's Cholla Power Plant on August 24, 2021 and the Four Corners Plant on August 25, 2021. Pursuant to these on-site visits, we observed the following at both power plants: (1) plant operations, (2) coal inventory at the plants, (3) ash pond remediation to date, (4) interviewed plant personnel including the plant manager at each plant. At Four Corners, Larkin and EVA were allowed into the Navajo Transitional Energy Company ("NTEC") area to observe the testing lab and the NTEC-operated train that transports coal from the mine to the plant unloading area. We found both power plants and the mine unloading area at Four Corners to be well managed. The coal stockpile layout at Four Corners is particularly helpful in delivering coal with a consistent quality as APS can blend coal from different areas as it is feeding the surge bins.

28. With regard to APS's procedures for taking physical inventories of coal, at Four Corners, the Company does not maintain any coal stockpiles because the coal is stockpiled adjacent to Four Corners by NTEC. Physical inventories of coal stockpiling at the Cholla plant are undertaken each spring and fall. A coal pile survey (using GPS drive-over) is conducted (by a third party) to measure the size of the coal pile. Each fall, a drilled core sample test of the coal pile is taken to analyze the density of the coal pile. If the GPS survey results show a deviation of < > 5 percent from the Cholla coal pile inventory volume, an adjustment is made to the APS coal pile book inventory. The last coal inventory adjustment at Cholla was made in 2012. The lack of the need to make coal inventory adjustments at Cholla indicates that APS's calculations for inventory and fuel burns have been reasonably accurate.

29. The includable fuel costs in the PSA are recorded in the following FERC Accounts: (1) 501 – Fuel (Steam), (2) 518 – Fuel (Nuclear) less independent spent fuel storage installation ("ISFSI") regulatory amortization, and (3) 547 – Fuel (Other Production). In the Company's confidential monthly PSA workpapers, APS breaks out fuel expense by (1) gas generation, (2) gas generation under tolling agreements, (3) gas hedges and mark-to-market expense, (4) oil generation, (5) coal generation, and (6) nuclear generation. We reviewed the monthly confidential PSA workpapers electronically in Excel for the categories of fuel costs noted above and tied the amounts back to APS fuel expense reports contained within the confidential PSA workpapers. No exceptions were noted.

30. The Company retired the Navajo Units 1-3 during the fourth quarter of 2019 and the monthly coal costs for Navajo decreased significantly beginning in November 2019. Beginning in March 2020 and continuing through January 2021, the Company's fuel expense reports included monthly costs for Navajo totaling $89,000, which reflects the amortization of a previously paid settlement that was negotiated with Peabody Energy ("Peabody"), and which has been allocated to final reclamation costs for Navajo. Final reclamation costs are recovered through the PSA with the amortization of these costs scheduled to be completed in April 2026.

31. We were unable to directly tie the total year-end fuel costs reflected in the monthly confidential PSA workpapers to APS's FERC Form 1 filings. Specifically, for 2019 there was a $17,576,986 difference between the monthly confidential PSA workpapers

and the 2019 FERC Form 1. For 2020, there was a ($56,206,618) difference between the PSA workpapers and the 2020 FERC Form 1. APS provided a reconciliation of the Company's overall 2019 and 2020 fuel costs from the confidential monthly PSA workpapers to the respective 2019 and 2020 FERC Form 1 filings. The variances between fuel expense in the 2019 and 2020 PSA workpapers and 2019 and 2020 FERC Form 1 filings is attributed to the deferred mark-to-market exclusions. As part of its reconciliation, the Company provided screenshots from its general ledger from which we verified the reconciliation amounts to the monthly mark-to-market exclusions. No exceptions were noted.

32. For January 2021, we tied the fuel costs from the Company's PSA workpapers to the monthly fuel expense reports. No exceptions were noted.

33. Pursuant to the previous finding and the Company's explanations and reconciliations, coupled with tying amounts to the fuel expense reports and FERC Form 1 filings, we conclude that APS's fuel costs were generally accurately stated for the review period.

34. The Company's confidential monthly PSA workpapers break out purchased power costs by Long-Term Purchased Power Expense, Market Purchased Power Expense and Other Purchased Power Expense. We reviewed the monthly confidential PSA workpapers electronically in Excel for the three categories of purchased power costs and tied the amounts back to two tabs titled "Level 3" and "Level 3 Tie Out", which represents APS's general ledger. No exceptions were noted.

35. We were unable to directly tie the total year-end purchased power costs reflected in the monthly confidential PSA workpapers to APS's FERC Form 1 filings. Specifically, for 2019 there was a $22,633,423 difference between the monthly confidential PSA workpapers and the 2019 FERC Form 1. For 2020, there was a $102,066,640 difference between the PSA workpapers and the 2020 FERC Form 1. APS provided a reconciliation of the Company's overall 2019 and 2020 purchased power costs from the confidential monthly PSA workpapers to the respective 2019 and 2020 FERC Form 1 filings. The variances between purchased power expense in the 2019 and 2020 PSA workpapers and 2019 and 2020 FERC Form 1 filings were attributed to (1) monthly broker fees booked to FERC Account 557.1, and (2) monthly PSA deferral expense booked to FERC Account 555.7. We tied the broker fees and PSA deferral expense to APS's general ledger. No exceptions were noted.

36. For January 2021, we tied the purchased power costs to the general ledger detail reflected on the Level 3 and Level 3 Tie Out tabs. No exceptions were noted.

37. With the Company's explanations and reconciliations shown above coupled with tying amounts to the general ledger and FERC Form 1 filings, we conclude that APS's purchased power costs are generally accurately stated.

38. During the review period, there were no customer outages caused by a lack of power supply nor did any coal supply interruptions occur during the review period.

39. As it relates to planned maintenance or overhead outages as well as unplanned outages at any of the Company's coal-fueled generating plants, APS uses a model to forecast the probable number of unplanned outages that are likely to occur in order to manage coal

inventory levels. For planned maintenance or overhead outages, APS forecasts maintenance outages to occur in planning models that are used to manage coal inventory levels. Specifically, any deviations to the planned inventory levels are managed through annual coal nominations governed by the coal supply agreements. Four Corners is a mine mouth operation where APS does not take possession of coal inventory until it is ready to use the coal for generation. Four Corners coal inventory levels are managed by the NTEC mine operator and coal supplier to a contractual level. Cholla uses annual nominations to manage inventory forecast deviations. APS was not involved in the management of coal inventory for the Navajo Generating Station, which was operated by SRP.

40. As it relates to unplanned outages during the review period, APS provided an "Event Report", which listed the unscheduled outages that occurred during the period January 2019 through January 2021 at the following generating units: Cholla, Four Corners, Palo Verde, Redhawk, West Phoenix, Ocotillo, Saguaro, Sundance and Yucca. Included in the Event Report were two columns titled "Cause Code" and "Cause Code Name." A separate tab on the Event Report is titled "Cause Code Descriptions" and includes a comprehensive listing of the Cause Codes. On a test basis, we compared the Cause Codes and Cause Code Names from the Case Code Descriptions tab to what is reflected on individual line items on the Event Report and noted no exceptions.

41. The Company provided the root cause analysis of its unplanned outages in documents titled (1) 2019 Summer Event Summary, (2) 2020 Summer Event Summary, and (3) 2020-2021 Winter Event Summary. These voluminous documents listed the same unplanned outages that are included on the aforementioned Event Report and included the corrective actions taken by APS and lessons learned from the unplanned outages.

42. The Company takes the following steps to minimize the impacts of unplanned outages: (1) reserves are held on a 24x7 basis to account for unscheduled events as applicable such as, intrahour flexibility, operating reserves and regulation, (2) communication between plants and dispatch is maintained on a 24x7 basis to ensure coordination, (3) APS plans and optimizes routine maintenance to ensure assets are maintained, and (4) APS manages generating unit wear, including starts and risk.

43. In its efforts to secure replacement power for unplanned outages, APS purchased replacement power from the market through Day Ahead or Real-Time availability as applicable.

44. The costs associated with the unplanned outages included in the PSA are reflected on the "Outage Cost" tab of the Company's monthly confidential PSA filings and are broken out by generating facility. The unplanned outage costs are shown as gross replacement cost less avoided costs resulting in actual net replacement cost.

45. [redacted]

46. In terms of hours, the unplanned outages at Cholla Units 1 and 3 during 2019 totaled 471.46 hours. The unplanned outages at Cholla Units 1 and 3 during 2020 and January 2021 totaled 363.37 hours.

47. [redacted]

48. In terms of hours, the unplanned outages at Four Corners Units 4 and 5 during 2019 totaled 1,157.60 hours, with Unit 4 being out of service for unplanned outages by 209.42 hours, and Unit 5 by 947.78 hours. The unplanned outages at Four Corners Units 4 and 5 during 2020 and January 2021 totaled 1,909.44 hours, with Unit 4 being out of service for unplanned outages by 1,121.66 hours, and Unit 5 by 787.78 hours.

49. The Equivalent Forced Outage Factors ("EFOFs") for Four Corners Unit 4 for 2019 and 2020 were 2.4 percent and 12.8 percent, respectively. The EFOFs for Four Corners Unit 5 for 2019 and 2020 were 10.8 percent and 8.1 percent, respectively. According to the Generating Availability Data System ("GADS") database, the industry benchmark EFOFs for 2019 and 2020 were 6.6 percent and 11.7 percent, respectively, so Four Corners Units 4 and 5 EFOFs in 2019 and 2020 were generally in line with industry experience.

50. The amount of outage costs included in the PSA consists of the Actual Net Replacement Cost, offset by the Normalized Net Replacement Cost. The difference between these amounts (i.e., actual greater/(less) than Normalized Net Replacement Cost) is multiplied by a retail allocation factor, which is calculated from the Company's public PSA filings on Schedule 3 whereby PSA retail energy sales are divided by total native load energy sales. We reviewed the Company's confidential PSA workpapers, which has these calculations for each month of the review period on the tab titled "Outage Costs." No exceptions were noted.

51. The Palo Verde nuclear plant had only three unplanned outages during the review period. Specifically, there were two unplanned outages at Palo Verde in 2019 (Unit 2 in August and Unit 3 in November) and one unplanned outage at Unit 2 in March 2020. The net replacement costs for the two unplanned outages in 2019 were $386,000 and $38,000, respectively, while the actual net replacement cost for the March 2020 unplanned outage was $322,000. The fact that there were only three unplanned outages during the review period indicates that the Palo Verde units are well maintained and operated effectively as intended during the review period.

52. We reviewed the unplanned outages associated with APS's gas/oil fired, combined cycle ("CC") and combustion turbine ("CT") generating units during the review period. With the exception of August 2019, we noted a number of instances during the review period in which certain generating facilities encountered unplanned outages that lasted a month or longer (e.g., for 30 days or 720 hours and/or 31 days or 744 hours). These extended

unplanned outages occurred at the various combustion turbine, combined cycle and gas-fired units at the Ocotillo, Redhawk, Saguaro, West Phoenix and Yucca generating facilities.

53. The EFOF benchmark in 2019 for combined cycle units from the GADS database was 4.68 percent, which is generally in line with the EFOFs for West Phoenix CC2 and CC3 which were 2.73 percent and 4.75 percent, respectively. However, the 2019 EFOFs for West Phoenix CC1 and CC4 were well above the industry benchmark at 21.13 percent and 39.85 percent, respectively. The unplanned outages for West Phoenix CC4 relate to the tripped steamer which caused this generating unit to be out of service for nearly five months (see Findings 56-58 below).

54. In 2020 there was only one unplanned outage at West Phoenix CC4, which occurred in May and lasted 221.08 hours resulting in a EFOF of 2.52 percent (221.08 / 8,760), which is below the 2020 industry benchmark for combined cycle units of 4.84 percent (per GADS).

55. For unplanned outages at combined cycle units, replacement power costs (if any) are reflected in the confidential PSA workpapers. The Company does not calculate replacement power costs for combustion turbines since the power that would have otherwise been generated from CT units is assumed to be replaced with power from another APS-owned CT generator at similar cost.

56. West Phoenix CC4 encountered an unplanned outage that lasted from January 1, 2019 through May 26, 2019, or nearly five months (approximately 3,491 hours). According to the Event Report provided in response to Staff data request 1.44, the five-month long unplanned outage at West Phoenix CC4 was due to a "vibration of the turbine generator unit that cannot be attributed to a specific cause such as bearings or blades." In addition, the Event Report further described the outage being related to a "steamer tripped offline" and that the unit needed to be off for troubleshooting.

57. With regard to why it took five months to repair the tripped steamer at West Phoenix CC4, this was a major unplanned outage that had a longer duration than a typical reliability maintenance outage, which was primarily due to the Company needing to refurbish the rotor and to replace the L0 turbine blades. Refurbishing the rotor was scheduled to be complete in eight weeks but because the turbine blades needed to be manufactured off-site, the outage duration was extended.

58. [redacted]

59. The capitalized and O&M expense for repairing the equipment at West Phoenix CC4 was approximately $5.5 million. However, none of these costs were flowed through the PSA.

60. There was no clear upward or downward trend in the capacity factors or Equivalent Availability Factors ("EAFs") for Cholla and Four Corners in 2019 or 2020, or for Navajo in 2019 as the capacity factors and EAFs fluctuated not only over the last ten years (i.e., 2010 through 2020), but also during the review period. We compared the

2019 and 2020 capacity factors for Cholla, Four Corners and Navajo to the benchmarks compiled by the U.S. Department of Energy ("DOE") for 2019 and 2020. Other than Cholla Unit 1 in 2019, which had a net capacity factor of 28.7 percent, the capacity factors for Cholla and Four Corners in 2019 and 2020 (and 2019 only for Navajo) were in line with, or above the DOE benchmarks for 2019 and 2020. We performed a similar analysis with regard to APS's sources of generation other than coal (i.e., nuclear natural gas, renewables) and noted that the capacity factors of these generating units were generally in line with the DOE benchmarks for 2019 and 2020.

61. Despite the noted fluctuations in capacity factors and EAFs discussed in the previous finding, there were no customer outages attributable to a lack of power supply during the review period, nor did APS experience any disruptions in its coal supply during the review period.

62. With regard to the electronic (i.e., Excel) versions of the PSA filings and related confidential PSA workpapers, we found that tying certain amounts among the tabs within the monthly filings (public and confidential) and/or tying amounts from the confidential PSA workpapers to the public PSA filings was challenging due to the Company hard coding data versus using Excel's formula function (see Audit Recommendations).

63. Upon reviewing the confidential monthly PSA workpapers, for most of the review period, Larkin tied out the amounts reflected on the PSA Cost Detail tab in the confidential PSA workpapers to the public PSA filings. However, in some instances, we noted inconsistent information between what was reflected on the PSA Cost Detail Tab in the confidential PSA workpapers to what was reported on Schedule 3 from the public monthly PSA filings. APS conceded in discovery that these were input errors. While these input errors did not have a material impact on the PSA rate, in our view, APS should strive to be more diligent when compiling its PSA filings and workpapers to avoid these types of errors (see Audit Recommendations).

64. APS has an established hedging program for its gas purchases, the primary purpose of which is to reduce the impact of natural gas pricing volatility. APS's gas price hedging program involves obtaining hedges for future gas price volatility for up to five years into the future. Beginning in 2020, APS temporarily suspended its hedging activities for future years 4 and 5 of its hedging program due to economic uncertainties and consideration of clean energy standards across the Western Region. As noted in Chapter 3 of our report, the Company's decision to suspend its hedging activities for years 4 and 5 was reasonable. Years 4 and 5 of APS's 2020 hedging program are calendar years 2024 and 2025, so the temporary suspension of hedging activity did not impact hedging costs during the review period.

65. The Company provided a document titled "Process: Commodity Hedge Compliance Process", which is APS's policies and procedures related to hedging. Upon reviewing this document, we find that APS's procedures for its hedging activities are reasonable.

66. The hedging processes discussed in the Commodity Hedge Compliance Process document were not incorporated into the monthly PSA filings during the review period. Specifically, while the Hedge Compliance Process helps to moderate the risks of gas price volatility and poses limitations on and provides guidance for hedging activities,

there is not a direct reconciliation to the monthly PSA filings. The PSA filings reflect the costs of the hedging transactions that are measured by the Hedge Compliance Process.

67. With regard to the hedging activities reflected in the PSA workpapers, we noted that APS's confidential Excel PSA workpapers included a tab titled "Gas Costs", which is a schedule called Actual Natural Gas Fuel Costs. This schedule breaks out APS's individual hedging activities by (1) long-term purchases (one month or longer), (2) short-term purchases (spot market and less than one month), (3) short-term sales (spot market and less than one month), and (4) prior period adjustments. We tied the monthly amounts back to the Company's monthly fuel expense reports that are prepared by APS's Generation Accounting and to APS's confidential PSA workpapers. Other than a couple of immaterial differences, no exceptions were noted.

68. During a Microsoft Teams meeting on October 29, 2021, the Company stated that costs associated with hedge liquidations (discussed in the previous finding) are included in the PSA. We verified this by tracing the hedge liquidations amounts from APS's monthly confidential PSA workpapers to the public PSA filings. No exceptions were noted.

69. APS records fossil chemical (and water) costs in FERC Accounts 502 and 549, including lime, sulfur and ammonia, which corresponds to Section 9 (Allowable Costs) in the PSA POA. APS provided a breakout of lime, sulfur and ammonia costs included in the public monthly PSA filings during the review period. The Company included labor costs in the breakout of chemical costs related to Four Corners because the chemicals and reagents are volatile and cannot be transported safely in useable form and must therefore be processed on site by APS employees.

70. We tied the chemical costs, which related to Cholla and Four Corners, to Schedule 3 (PSA Year Forward Component Tracking Account) of the public monthly PSA filings for each month of the review period. No exceptions were noted.

71. The Company maintains an inventory of California Carbon Allowances ("CCA") to fulfill obligations within California requirements. APS provided documentation related to the accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory. For 2019, the Company's total CCA inventory was 277,000 CO_2 emission allowances at a total value of $4,522,190. The majority of the 2019 monthly emission allowances were open and subsequent to the delivery dates, the open quantity of 2019 emission allowances totaled 265,437 at a cost of $4,361,539. We tied the monthly emission allowance valuations to the Company's general ledger detail. No exceptions were noted.

72. For 2020, the Company's CCA total inventory was 380,000 CO_2 emission allowances at a total value of $6,306,020. All of the 2020 monthly emission allowances were open and subsequent to the delivery dates, the open quantity of 2020 emission allowances totaled 372,207 CCAs at a cost of $6,173,305. We tied the monthly emission allowance valuations to the Company's general ledger detail. No exceptions were noted. There was no CCA emission allowance activity in January 2021.

73. The Company did not sell any emission allowances during the 2019, 2020 and January 2021 review period, which we verified upon reviewing Schedules 2 and 3 from APS's public PSA filings. No exceptions were noted.

74. There were no external audits conducted during the review period related to fuel and power purchases, fuel transportation, emission allowances, replacement power, fuel inventory, plant operations and fuel and purchased power.

75. We reviewed nine internal audit reports all of which were related to plant operations and were conducted at various points during 2019 and 2020 (there were no internal audits listed for January 2021). For each of the nine internal audit reports we reviewed, PinnacleWest's Audit Service Department concluded that the control deficiencies it identified were appropriately mitigated by the action plans developed and implemented by APS management.

76. APS has not conducted an internal audit of the processes and calculations associated with any of its PSA filings during calendar years 2019 and 2020 and January 2021. The Company considers the process of completing the PSA filings to be generally considered a low inherent risk, in part because there are Sarbanes-Oxley ("SOX") controls in place for fuel calculations and the preparation of the PSA filing. APS tests those SOX controls for design and operating effectiveness twice annually. These SOX controls are performed in support of (1) the fuel and purchased power calculations, and (2) PSA filings, and that such controls ensure the completeness, accuracy and validity of fuel and purchase power transactions from inception through the regulatory and regulatory reporting processes. For 2019 and 2020, the Company concluded that all the SOX controls were operating effectively in each of the two testing periods. With regard to SOX testing performed in January 2021, such testing had not been performed during that month as it was prior to the mid-year point in which the first of the two annual testing of these controls was performed.

Audit Recommendations

1. All future APS fuel and purchased power audits should include a prudence review of all major fuel-related agreements including commodity and transportation.
2. All future APS fuel and purchased power audits should include a prudence review of all power purchase agreements.
3. APS should investigate whether the pricing under the Cholla coal supply agreement can be restructured in order to improve the consistency of the plant operations. APS should provide the results of this review to the Commission within six months.
4. APS should investigate whether the pricing under the Four Corners coal supply agreement can be restructured in order to improve the consistency of the plant operations. APS should provide the results of this review to the Commission within six months.
5. The APS Hedge Program should be reviewed to determine what if any changes should be made to address price uncertainty with regard to natural gas price volatility.
6. We recommend that APS periodically update its operational and coal supply management plans to assure that the remaining coal inventory at Cholla and Four Corners is used to generate electricity to the fullest extent possible before each plant closes, so the remaining coal inventory at those plants does not result in a significant stranded cost upon plant closure. Currently, Cholla is scheduled to close in 2025 and APS is using a

retirement date for Four Corners of 2031, although there are pressures from environmental groups, and potentially from co-owners, that could result in an earlier date for plant closure.

7. During the review period, unplanned outages at Four Corners resulted in APS (and the co-owners) incurring costs for replacement power. We recommend that the Company review plant operations and its plans for scheduled maintenance to avoid having significant additional unplanned outages at the plant during periods when the plant's capacity is needed to meet demand and/or when the cost of replacement power is high.

8. APS should include in a footnote in its PSA filings, the amounts of replacement costs related to unplanned outages at nuclear, coal and combined cycle generating facilities, and to also include a description regarding the type and reason(s) for each extended unplanned outage.

9. With regard to the electronic (i.e., Excel) versions of APS's PSA filings and related confidential PSA workpapers, we found that tying certain amounts among the tabs within the monthly filings (public and confidential) and/or tying amounts from the confidential PSA workpapers to the public PSA filings was challenging due to the Company hard coding data versus using Excel's formula function. Therefore, we recommend that the Company expand its use of Excel's formula function in the PSA related Excel files in order for future auditors to be able to efficiently analyze APS's PSA filings and related confidential workpapers in terms tracing amounts to supporting documentation and calculations.

10. Although the input errors we noted in the Company's PSA filings did not have a material impact on the PSA rates, we recommend that APS develop and/or enhance its existing internal review procedures in order to avoid input errors when compiling the monthly PSA filings and related confidential PSA workpapers.

11. We determined that the PSA was working as designed during the review period January 2019 through January 2021. Therefore, we recommend that the current structure of the PSA be maintained, subject to being reviewed periodically in view of changing conditions.

Prior Fuel Audit Recommendations and Implementation

In accordance with Commission Decision No. 73183 dated May 24, 2012, a fuel and purchased power audit of APS was conducted by the firm Schumaker & Company ("previous auditor"). The previous auditor's fuel audit report and accompanying direct testimony was filed with the Commission on March 21, 2017 in Docket No. E-01345A-16-0123. Pursuant to its fuel audit of APS, Schumaker developed the following recommendations, which are numbered in a manner consistent with the Schumaker fuel audit report in that docket:

Recommendation II-1: Perform a study to determine if changes can be made to the coal supply chain to yield some plant efficiencies.[4]

[4] This recommendation relates to the Cholla Plant.

Recommendation III-1: Have internal or external auditors audit PSA filings, as they have yet to address PSA filing procedures

Recommendation III-2: Improve spreadsheet usage and associated references and cross references on how used.

Recommendation III-3: Incorporate more detailed implementation steps, including sample screen prints, in Monthly PSA Filings documentation, plus risk management documentation, which should be reviewed and modified, as necessary, at least annually.

Recommendation III-4: Develop formal written documentation for supplemental fuel charges and refunds.

In Decision 76295 dated August 18, 2017, the Commission required APS to implement the foregoing recommendations from the prior fuel audit.[5] However, the Company proposed modifications to the recommendations which were agreed to by Staff. As a result of these modifications, the recommendations were implemented within an 18-month timeframe, with certain milestones met at six month and 12-month periods (see additional discussion below).

Larkin asked the Company whether and how it complied with and/or implemented each of the recommendations listed above from the prior fuel audit. APS's response to Staff data request 4.3(b) stated that all five recommendations discussed above from the prior audit were implemented by APS and were in place during the 2019, 2020 and January 2021 review period. In its response to Staff data request 1.138, the Company stated it has complied with all of the recommendations from the prior audit and provided several confidential attachments in support of APS's contention. Specifically, the Company provided three letters that were previously forwarded to Staff and which were referred to as Status Report on Fuel Audit Recommendations. Each of these status report letters, which are dated February 20, 2018, August 17, 2018 and February 19, 2019, addressed the prior audit recommendations as follows:

- Status Report letter dated February 20, 2018: Recommendation II-1.
- Status Report letter dated August 17, 2018: Recommendations III-1, III-3 and III-4
- Status Report letter dated February 19, 2019: Recommendation III-2

The Company's compliance with the prior fuel audit recommendations is discussed below.

Recommendation II-1: Perform a study to determine if changes can be made to the coal supply chain to yield some plant efficiencies

For this recommendation, the Company provided a confidential attachment which was a study prepared by RPMGlobal USA, Inc.[6] ("RPMGlobal") titled "Cholla Coal Plant Coal Supply Chain Evaluation", which was dated August 23, 2017. This report was previously submitted to Staff on February 20, 2018.

[5] A sixth recommendation from the previous auditor report, which would have required APS to reconfigure its systems to disallow transactions when a counterparty is overexposed, was removed as discussed on page 29 of Decision No. 76295. Staff agreed to this modification.

[6] RPMGlobal is a consulting and advisory services firm which focuses on delivering mining productivity through technology enablement and service offerings.

We reviewed RPMGlobal's report on the Cholla Plant and noted that RPMGlobal made the following findings as a result of its review of the coal supply chain and the operations at the Cholla Plant:

- RPM did not identify any obvious inefficiencies in the system.
  - The system design and operation are reasonable. RPM did not observe any instances where modifications to either the system layout or its operation would yield significant savings.
  - Cholla's relatively short operating horizon largely precludes substantial capital investment. According to media reports, APS will cease using coal at Cholla by the end of 2025. In addition, PacifiCorp, the owner of Cholla Unit #4, indicated in its most recent Integrated Resource Plan (IRP) that its preferred generation portfolio would include retirement of Unit #4 by the end of 2020. As a result, major modifications to the coal handling system, which would generally require a longer payback period, are not an option.
- Both the Coal Sales Agreement (CSA) with Peabody Energy (Peabody) and the transportation agreement with the BNSF Railway (BNSF) require pro-rata deliveries, i.e., shipments in roughly uniform monthly quantities. As discussed further in Section 5, this requirement is typical in the industry, as it results in the most efficient use of mining and transportation capital. RPM believes that modifications to the delivery schedules in the Peabody and BNSF contracts would inevitably involve additional costs. The magnitude of such cost increases is almost certainly moot, however, as, APS advises that the pro-rata provisions of the CSA cannot be modified. Scheduling coal deliveries to follow plant load, therefore, does not appear feasible.
- Due to economic factors, including relatively less expensive gas-fired generation and the availability of significant quantities of renewable power, Cholla, like many other coal-fired plants, no longer operates as a base load plant, but instead operates on a seasonal basis. Given the now-seasonal nature of Cholla coal use, the Cholla stack-out pile may well be the most cost-efficient area for storage and reclaim of coal that cannot be burned as it is delivered.
- There are no conceivable circumstances under which the stack-out inventory could be completely eliminated. In addition to serving as a storage and reclaim stockpile for inevitable discrepancies between coal receipts and burn and a buffer against major disruptions as the coal source or in the transportation system, the stack-out pile is also essential to blend coals of different qualities to ensure a relatively uniform quality feed to the boilers. Therefore, APS would continue to incur many of the current costs associated with maintaining this inventory even if some (as yet unidentified) changes in coal deliveries or storage could minimize the volume of stack-out coal. Because some coal will continue to be stored temporarily in the stack-out pile, maintenance equipment (such as dozers and the water truck) and operating personnel will still be necessary.

- Truck delivery is not feasible for both technical and economic reasons.

- Even if they were feasible, alternative delivery methods such as truck delivery would not appear to offer any substantial savings. Given the much higher freight rates associated with truck deliveries compared to rail deliveries, overall coal transportation and handling costs would likely increase substantially.

On page 5 of its report, RPMGlobal summarized its findings with regard to Cholla's coal supply chain as follows:

> RPM believes, therefore, that the current coal delivery system, including contractually mandated pro-rata deliveries, transportation via the BNSF, and use of the stack-out pile to accommodate variations between load and deliveries, is the most efficient system available at Cholla. The short life expectancy of the Cholla Plant and the resulting capital spending constraints preclude wholesale redesign of this system.

Larkin Conclusion: Based on the foregoing, Larkin concludes that APS complied with Recommendation II-1 from the prior fuel audit.

Recommendation III-1: Improve spreadsheet usage and associated references and cross references on how used

For this recommendation, the Company provided confidential Attachment A which is titled "Confidential PSA Documentation", which documents the worksheets included in the confidential PSA filings[7] and the process for updating those files. Specifically, for each worksheet, there is (1) a brief description of the worksheet, a summary of how the data flows through the worksheet, (3) a description of any internal or external checks, and (4) a list of the sources for the data. The worksheets (i.e., tabs from the confidential PSA filings in Excel) include the following: (1) Summary Tab, (2) Energy Transactions Tab, (3) Off-System Margins Tab, (4) Margin Explanations Tab, (5) Generation (2) Tab, (6) Gas Costs Tab, (7) Outage Costs Tab, (8) Filing Forecast Tab, (9) Balance Graph Tab, (10) PSA Cost Detail Tab.

There are additional tabs included in APS's confidential PSA filing worksheets, which the Company indicated are inputs that were created during the monthly billing process. APS's monthly confidential PSA filings are discussed in further detail in Chapter 4 of this report.

Larkin Conclusion: Based on the foregoing, Larkin concludes that APS complied with Recommendation III-1 from the prior fuel audit.

Recommendation III-2: Have external or internal auditors audit PSA filings, as they have yet to address PSA filing procedures

For this recommendation, the Company provided a confidential attachment which was an internal audit report prepared by PinnacleWest Capital Corporation[8] ("PW") Internal Audit titled

[7] The monthly Confidential PSA filings were provided, along with monthly non-confidential PSA filings in the response to Staff data request 1.95 and are discussed in more detail in a later section of this report.
[8] PinnacleWest Capital Corporation is APS' parent company.

"Fuel and Purchased Power Costs Audit # 2018-1001", which was dated October 17, 2018. This report was previously submitted to Staff on February 19, 2019.

The stated objective of this internal audit was to evaluate the effectiveness of the Company's fuel and purchased power procurement practices in order to ensure they were in line with management's expectations, and to ensure adequate actions had been taken to address the control gaps noted in the prior fuel audit report. In addition, the scope of this internal audit consisted of the internal audit group testing the design and operating effectiveness of the controls related to the Company's fuel and purchased power processes. Specifically, the internal audit group reviewed APS's PSA transactions from the period January 1, 2017 through June 30, 2018 as well as PSA filings submitted to the Commission from January 1, 2018 through June 30, 2018. Internal audit also reviewed actions taken by APS to address control gaps that were noted in the prior audit.

The procedures performed by the internal audit group included (1) interviewing key Company personnel responsible for administering the PSA process and PSA filings, (2) reviewing the Company's fuel and purchased power processes and procedures for completeness and effectiveness, (3) on a sample basis, verifying the PSA contract administration and billing practices for accuracy and timeliness, (4) confirming that the PSA reports filed with the Commission were complete, accurate, timely and adequately supported, and (5) reviewing the Company's responses related to the control gaps noted in the prior fuel audit.

In the Executive Summary of the internal audit report, the PW internal audit group did not identify any findings and concluded that APS had an overall rating of "Effective", which is defined as "overall controls are designed and operating effectively with limited residual risk of exposure to the Company."

Larkin Conclusion: Based on the foregoing, Larkin concludes that APS complied with Recommendation III-2 from the prior fuel audit.

Recommendation III-3: Incorporate more detailed implementation steps, including sample screen prints, in Monthly PSA Filings documentation, plus risk management documentation, which should be reviewed and modified, as necessary, at least annually

For the portion of this recommendation that relates to incorporating more detailed implementation steps (including sample screen prints) in the monthly PSA filing documentation, the Status Report letter dated August 17, 2018 that APS provided to Staff stated that this is addressed in confidential Attachment A with regard to Recommendation III.1 (see discussion above).

With regard to the portion of this recommendation that relates to risk management documentation, the Company provided confidential Attachment C, which is titled "Updated Energy Risk Management Process." Specifically, this document, which is dated March 2018 and which APS deemed highly confidential, is APS's Energy Risk Management Process. In the Overview section of this document, it states:

> APS's regulated electricity business consists of traditional retail and wholesale electricity related activities. In connection with the management of these activities, APS enters into a variety of energy and energy related commodity transactions to meet its energy requirements, including real-time, day-ahead and

> forward contracts for the sale or purchase of electricity and natural gas and the acquisition of necessary electric transmission and natural gas pipeline capacity. This APS Energy Risk Management Process Document (herein referenced as "*Guidelines*") applies to all APS Resource Management energy and energy related commodity transactions, including transactions involving physical delivery as well as financial instruments, such as swaps, options, futures, exchanges, or other similar contractual agreements, which may be used as a means to manage financial risk associated with the Company's energy requirements. (The *Guidelines* expressly do not govern (a) capital projects, including the development, construction or acquisition of generation facilities, (b) any non-APS transactions, or (c) any transactions not executed by APS Resource Management). In order to help ensure that the energy risk management objectives will be met, the Company has adopted these *Guidelines*. Unless otherwise stated herein, any reference to *Guidelines* will be deemed to include all Attachments.

As noted above, the Company indicated on the Attachment C cover page that the Energy Risk Management Process document was an updated version. We asked APS to provide the date of the original version of this document. In its response to Staff data request 6.2, the Company stated that the original Energy Risk Management Process document was created on September 27, 2005 in support of Trading Floor operations. With regard to the Company updating this document in the context of Recommendation III-3 from the prior audit, the Company stated that the prior fuel audit report recommended that the energy risk management documentation be updated on an annual basis. In addition, while a regular review process was already in place prior to Recommendation III-3, such reviews were not performed annually. Pursuant to the prior recommendation, the Company has performed an annual review of the energy risk management documentation since 2018.[9] According to the response to Staff data request 6.2, since Recommendation III-3 was issued in the prior fuel audit, the Company the Energy Risk Management Process document was updated and approved by the Director of Enterprise Risk Management in April 2018, April 2019 and January 2021.[10] With regard to 2020, the Company stated that a delay occurred in approving the 2020 update due to the Covid-19 pandemic.

Larkin Conclusion: Based on the foregoing, Larkin concludes that APS complied with Recommendation III-3 from the prior fuel audit.

Recommendation III-4: **Develop formal written documentation for supplemental fuel charges or refunds**

For this recommendation, the Company provided confidential Attachment B which is titled "Supplemental Fuel Refund Documentation", and which is a Compliance Memo of Understanding dated July 11, 2018, the subject of which is Refunds Subject to PSA.

This memo provides background information related to an approved rate settlement dated May 16, 2012 in which a previous 90/10 PSA sharing mechanism was eliminated in favor of 100 percent recovery of costs and savings related to fuel and purchased power being recovered through the PSA (per the PSA POA). In addition, the memo states that no material changes

[9] See Staff data request 6.2.

[10] The updated version of the Energy Risk Management Process from January 2021 was provided in Staff data request 1.1.

impacting the recovery of fuel and purchased power costs through the PSA were implemented pursuant to an approved rate settlement in August 2017.

Under a section of the memo titled "Issue(s)", it states that in rare circumstances, APS may receive a refund from suppliers for costs that have been deferred through the PSA and the issue identified was how to record such refunds in order to properly allocate them between ratepayers and shareholders. The memo includes the following solution to properly allocate any refunds for costs deferred through the PSA:

> In the event that APS is subject to a refund, the refunded amounts will be recorded as an offset to the PSA expenses in the period in which the refund is received. This will reduce the fuel and purchased power expense for that month. If that refund relates to a period that was prior to the 100% deferral being approved (prior to May 16, 2012), those amounts will be allocated proportionately to the affected cost classes. Allocation methodology will be determined at the time of refund based on the information available, and may include allocation based on volume, dollars, units, etc. For refunded amounts that can be directly attributable to amounts which were not recovered through the PSA, those amounts will be recorded as pass-through to shareholders. Because these refunds are infrequent in nature, documentation will be created at the time of the refund to ensure that evidence exists as to the methodology used and the impact to the ratepayers and shareholders.

Upon reviewing this memo, we sought clarification from APS in order to confirm this was the Company's response to Recommendation III-4 from the prior fuel audit. In its response to Staff data request 4.3, the Company stated:

> Yes. The Company has complied with this recommendation from the prior fuel audit. Please see Attachment B as part of APS21FA00004 provided in the Company's response to Staff 1.138.

As previously noted, the passage above is from Attachment B (i.e., APS21FA00004) from the response to Staff data request 1.138. In addition, in its response to Staff data request 4.4, APS confirmed that Attachment B from the response to Staff data request 1.138 reflects the Company's compliance and implementation of Recommendation III-4 from the prior audit.

Larkin Conclusion: Based on the foregoing, Larkin concludes that APS complied with Recommendation III-4 from the prior fuel audit.

Audit Outline

The outline of the remainder of this report is as follows:

- Section 2 APS Background
- Section 3 Fuel Procurement Audit
- Section 4 Financial Audit

Appendices

Appendix A – Photographs of the Cholla Plant from August 24, 2021 On-Site Visit

Appendix B – Photographs of the Four Corners Plant from August 25, 2021 On-Site Visit

2 APS BACKGROUND

Background on Arizona Public Service Company

APS is an Arizona utility providing electricity to more than 1.26 million customers in 11 of Arizona's 15 counties. With its headquarters in Phoenix, APS is the largest wholly-owned subsidiary of the publicly traded Pinnacle West Capital Corporation ("PWCC").

According to its 2020 Form 10-K filing, APS owns or leases 6,321 MW of regulated generation capacity and has a mix of both long-term and short-term purchased power agreements for additional capacity, including a variety of agreements for the purchase of renewable energy. The generation portfolio as of the end of December 31, 2020 was as follows:

Exhibit 2-1
APS Power Plants

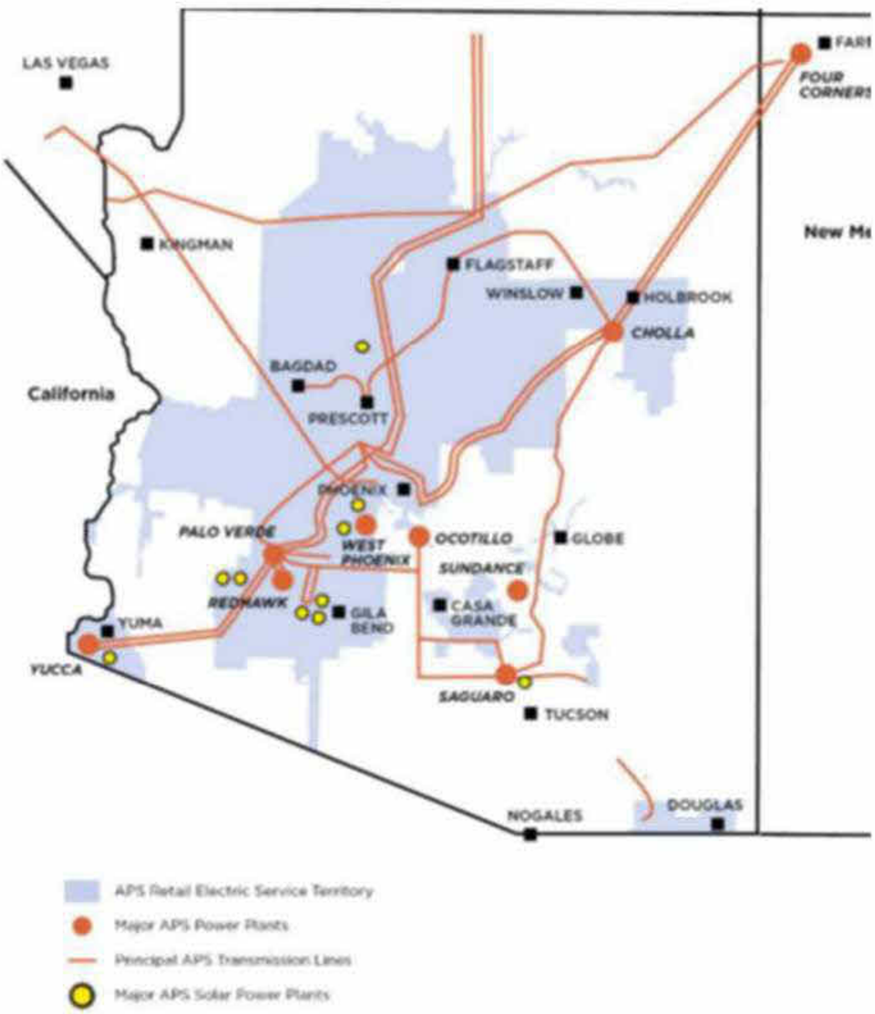
Category	Plant Name	% Owned*	Principal Fuel	Type	Capacity (MW)
Nuclear	Palo Verde	29.1%	Uranium	Base Load	1,146
Steam	Four Corners	63.0%	Coal	Base Load	970
	Cholla 1,3		Coal	Base Load	387
					1,357
Combined Cycle	Redhawk		Gas	Load Following	1,088
	West Phoenix		Gas	Load Following	887
					1,975
Combustion Turbines	Ocotillo 3-7		Gas	Peaking	620
	Saguaro		Gas	Peaking	189
	Doulas/Fairview		Oil	Peaking	16
	Sundance		Gas	Peaking	420
	West Phoenix		Gas	Peaking	110
	Yucca 1,2,3		Gas	Peaking	93
	Yucca 4		Oil	Peaking	54
	Yucca 5, 6		Gas	Peaking	96
					1,598
Solar	Cotton Center		Solar	As Available	17
	Hyder I		Solar	As Available	16
	Paloma		Solar	As Available	17
	Chino Valley		Solar	As Available	19
	Gila Bend		Solar	As Available	32
	Hyder II		Solar	As Available	14
	Foothills		Solar	As Available	35
	Luke AFB		Solar	As Available	10
	Desert Star		Solar	As Available	10
	Red Rock		Solar	As Available	40
	APS-Owned DE		Solar	As Available	31
	Other		Solar	As Available	4
					245
TOTAL					6,321

*100 percent unless noted

It should be noted that in 1986, APS entered into agreements with three separate Variable Interest Entities ("VIE") in order to sell and lease back interests in Palo Verde 2. According to the 2020 10-K filing, APS will retain the assets through 2023 under one lease and 2033 under the other two leases. At the end of the lease period, APS will have the option to purchase the leased assets at their fair market value, extend the leases for up to two years, or return the assets to the lessors.

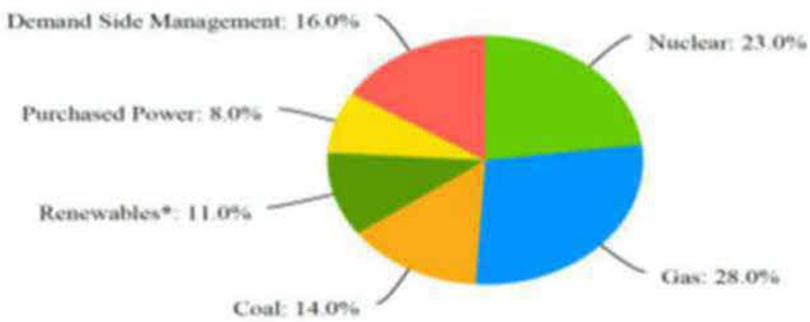
While all of APS service territory is within the state of Arizona, some transmission and generation assets extend into Nevada and New Mexico. The Four Corners power plant, a key plant for purposes of this audit, is located in New Mexico.

Exhibit 2-2
APS Service Territory



APS currently has a diverse generation portfolio. As shown in the exhibit below, the largest source of generation for APS in 2020 was gas at 28 percent. Nuclear followed at 23 percent.

Exhibit 2-3
Generation by Fuel Type



In January 2020, APS announced a Clean Energy Commitment which it describes as a "three-pronged approach" aimed at ultimately eliminating carbon-emitting resources from its electric generation resource portfolio. APS's clean energy goals consist of three parts:

- A 2050 goal to provide 100 percent clean, carbon-free electricity;
- A 2030 target of achieving a resource mix that is 65 percent clean energy with 45 percent of the generation portfolio coming from renewable energy;
- A commitment to end APS's use of coal-fired electricity generation by 2031.[11]

Rates

APS's current rates became effective August 19, 2017, pursuant to Decision No. 76295, dated August 18, 2017. The Decision approved the Settlement Agreement dated March 24, 2017. Decision No. 76295 approved a total base rate increase of $362.58 million. This amount is comprised of (1) a non-fuel base rate increase of $148.25 million, which includes providing for a return on and of plant that is in service as of December 31, 2016 ("Post-Test Year Plant"), twelve months beyond the test-year ending December 31, 2015; (2) a fuel base rate decrease of $53.63 million; and (3) the transfer from adjustor mechanisms of $267.95 million to base rates. This resulted in a net base rate increase of $94.624 million.

Pursuant to Commission Decision No. 77270, on October 31, 2019, APS filed a general rate case application (Docket No. E-01345A-19-0236) using adjusted test year sales and expenses for the Company's jurisdictional electric operations for the twelve months ended on June 30, 2019. On November 9, 2021, the Commission issued Decision No. 78317, which, among other things, ordered APS to revise its tariffs by changing its on-peak Time-of-Use ("TOU") period from 4 p.m. to 7 p.m. In addition, the Commission's ordered that the rates and charges and terms and conditions of service approved in Decision No. 78317 to become effective for all service rendered on or after December 1, 2021. As a result of an Open Meeting held on January 11-12, 2022, on January 31, 2022, pursuant to A.R.S. § 40-252, the Commission issued Decision No.

[11] APS does not exclude that carbon capture technology could allow continued use of coal and other fossil fuels.

78436, which was an Order revising certain portions of the TOU language contained in Decision No. 78317.

3 FUEL PROCUREMENT AUDIT

The fuel supply arrangements for APS consist of long-term contracts for the coal plants, long-term contracts for Palo Verde, and market purchases of natural gas. The natural gas purchases are commercially hedged per a defined and approved risk management plan 2019 Coal Procurement Performance.

Coal

APS operates two coal-fired power plants: Cholla and Four Corners. Plant information is provided in the exhibit below:

Exhibit 3-1
Cholla and Four Corners Coal-Fired Power Plant Specifications

Plant	Unit	MW	Ownership	Commissioned	Reitrement	
					Actual	Expected
Cholla	1	114	APS	1962	NA	2025
	2	289	APS	1978	2016	
	3	312	APS	1980	NA	2025
	4	414	PacifiCorp	1981	2020	
Four Corners	1	185	APS	1963	2013	
	2	185	APS	1963	2013	
	3	229	APS	1964	2013	
	4	745	APS-63%	1969	NA	2031
			PNM - 13%			
	5	745	SRP-10%	1970	NA	2031
			TEP-7%			
			NTEC-7%			

Cholla Power Plant

Cholla was a four-unit station. APS owned Units 1-3. PacifiCorp owned Unit 4. APS operated the plant. Unit 2 was retired in 2016. PacifiCorp retired Unit 4 at the end of 2020.

The requirements of the Cholla Plant are supplied under a 15-year contract with COALSALES, an affiliate of Peabody Energy signed in 2005 (the 2005 Agreement). The 2005 Agreement, was amended in 2013 (2013 Amendment) and in 2017 (the 2017 Amendment). The key terms of the base contract and the amendments are provided in Exhibit 3-2 below:

Exhibit 3-2
Summary of Cholla Contract and Amendments

Parties	APS with respect to Units 1-3 and an Operating Agent on behalf of PacifiCorp with respect to Unit 4 ("Buyer) and COALSALES LLC ("Seller")
Date	21-Dec-05
Term	January 1, 2006 though December 31, 2024
Source	Lee Ranch or El Segundo mines with substitution rights
Point of Delivery	FOB railcar at the mine

[redacted]

The primary motivation for the 2013 Amendment was Seller's contractually allowed right to reopen the price. While not specifically mentioned in the recitals to the 2017 Amendment, the second amendment was a settlement of a dispute between the Buyers and Peabody. APS described the situation in its 2016 10-K filing.

APS purchases all of Cholla's coal requirements from a coal supplier, an affiliate of Peabody Energy Corporation, that mines all of the coal under long-term leases of coal reserves with the federal and state governments and private landholders. On April 13, 2016, Peabody Energy Corporation and certain affiliated entities filed a petition for relief under chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the Eastern District of Missouri. Under the Coal Supply Agreement, dated December 21, 2005, Peabody supplied coal to APS and PacifiCorp (collectively, the "Buyers") for use at Cholla. APS believes that the Coal Supply Agreement terminated automatically on April 13, 2016 as a result of Peabody's bankruptcy filing. The Buyers filed a motion requesting that the Bankruptcy Court enter an order determining that the Buyers are authorized to enforce the termination provisions in the Coal Supply Agreement.

On May 13, 2016, Peabody filed a complaint against the Buyers in the bankruptcy court in which Peabody alleged that the Buyers breached the Coal Supply Agreement. On January 27, 2017, the bankruptcy court approved a settlement between the parties, and on February 6, 2017 the parties executed an amendment to the Coal Supply Agreement that allows for continuation of the agreement with modified terms and conditions acceptable to the parties.

The 2017 Amendment was not reviewed in the prior audit. Therefore, the prudence of this effective settlement was not addressed. APS indicated a Commission review is not automatically required. The Audit Team's experience is that a material contract/amendment is reviewed in the audit subsequent to its formation, particularly if it has a material impact on the cost of fuel to ratepayers. The 2017 Amendment does appear to have significant financial implications including the following:

- A payment due Seller from APS of [redacted] for failure to purchase minimum tons in 2016.
- A substantial predetermined liquidation payment to Seller if Buyers elect to terminate the supply obligations for one or more of the units. [redacted]
- A substantial predetermined per ton payment [redacted] due Seller for unshipped tons in each year remaining in the original contract.

The net effect of the 2017 Amendment is a buy-down of the prior contract tonnages and an exit ramp if one or more of the units were retired. The Audit Team has not concluded the 2017 Amendment to be imprudent. Payments being made pursuant to the 2017 Amendment after January 2021 (end of the period audited) should be reviewed in future audits and a future rate case.

Coal is delivered to Cholla by rail. During the review period, all of the coal was purchased under the contract with Peabody for coal from the El Segundo mine. As shown in the exhibit below, the delivered price for both 2019 and 2020 was about $42.00 per ton or $2.29 per MMBtu:

Exhibit 3-3
Purchases by Cholla

REPORTED PURCHASES BY CHOLLA

Year	Month	Tons	MMBtu/Ton	Sulfur	Ash	$/Ton	Cents/MMBtu
2019	1	133,735	18.87	0.91	12.80	43.21	229.0
2019	2	141,788	18.40	1.09	14.80	43.61	237.0
2019	3	193,057	18.44	1.19	14.90	43.15	234.0
2019	4	174,295	18.31	1.19	15.80	41.20	225.0
2019	5	117,785	18.24	1.11	16.40	40.49	222.0
2019	6	147,575	18.32	1.10	16.20	40.49	221.0
2019	7	163,679	18.44	1.11	15.60	42.60	231.0
2019	8	151,551	18.30	1.07	15.60	42.71	233.4
2019	9	122,713	18.40	1.04	15.30	44.90	244.0
2019	10	149,966	18.38	1.05	14.90	40.97	222.9
2019	11	135,302	18.25	1.09	14.90	41.61	228.0
2019	12	137,314	18.07	1.06	15.70	41.02	227.0
2019	**TOTAL**	1,768,760	18.37	1.09	15.24	42.16	229.5
2020	1	177,656	18.34	1.10	14.50	42.55	232.0
2020	2	158,019	18.25	1.13	15.30	42.52	233.0
2020	3	157,772	18.39	1.07	14.90	41.75	227.0
2020	4	156,701	18.36	1.06	15.10	43.15	235.0
2020	5	152,333	18.25	1.09	15.70	41.06	225.0
2020	6	138,249	18.40	1.16	15.40	41.77	227.0
2020	7	163,192	18.23	1.10	16.30	42.11	231.0
2020	8	138,552	18.46	1.07	14.90	40.98	222.0
2020	9	146,692	18.46	1.03	15.50	41.17	223.0
2020	10	152,188	18.56	1.09	15.30	42.13	227.0
2020	11	143,975	18.44	1.14	14.70	42.41	230.0
2020	12	153,340	18.03	1.16	16.90	41.29	229.0
2020	**TOTAL**	1,838,669	18.34	1.10	15.37	41.93	228.6

The closure of Unit 4 at the end of 2020 will significantly reduce volumes to the plant. While PacifiCorp's obligations under the Agreement are separate from APS's obligations, it is not clear that APS costs are not affected by the closure of Unit 4. If the purchases in the first seven months of 2021 are an indication, prices are up by about $3.00 per ton resulting in an increase from $2.29 per MMBtu to $2.48 per MMBtu.[12] The higher prices could have an adverse effect on plant operations.

Given the significant costs to APS for early termination of the Cholla contracts, it would behoove APS and Peabody to consider alternative pricing in order to maximize usage of the remaining units. Several strategies in play or being considered by others are seasonal pricing of coal, linking the price of coal to the power price, and the establishment of fixed and variable

[12] EIA 923 data for 2021.

components of the coal price such that the plants would be dispatched based upon variable costs. Increasing plant utilization would also serve to reduce O&M costs as well as wear and tear on the units.[13]

Four Corners Power Plant

Four Corners was a five-unit station. APS owned Units 1-3, while Units 4-5 are jointly owned. The ownership mix has changed over time. In 2013, APS acquired Southern California Edison's 48 percent ownership of Units 4 and 5, essentially replacing the capacity retired. In 2016, APS acquired El Paso Electric Company's ("El Paso") seven percent interest in Units 4 and 5. In 2018, the NTEC which owns the mine acquired El Paso's former seven percent share from APS.

APS has removed Units 1-3 from the site. As shown in the Google Earth view in the exhibit below, only Units 4 and 5 remain:

Exhibit 3-4
Aerial View of Four Corners

Four Corners is supplied by a mine mouth operation that was originally developed by Utah International for this plant. Utah International was acquired by General Electric in 1977. BHP acquired what became known as New Mexico Coal in 1984. In 2001, BHP became a part of BHP Billiton. In 2013, NTEC acquired the mine from BHP.

[13] Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices (naruc.org)

On December 13, 2013, Seller and the non-NTEC Buyers entered into the Four Corners 2016 Coal Supply Agreement (2016 Agreement). The coal contract that governs the current coal supply is the Amended and Restated Four Corners 2016 Coal Supply Agreement (the 2018 Agreement).

In late 2015, NTEC selected Bisti Fuels, a subsidiary of North American Coal Company, to operate the Navajo Mine. Bisti Fuels assumed this role in 2017. NTEC asked and received a provision that allowed it to assume direct mine management subject to the agreement of the Non-NTEC buyers. NTEC assumed mine management in July 2021.[14]

The basic commercial terms of the 2018 Agreement are summarized in Exhibit 3-5 below:

[14] While not specifically disclosed by APS, NTEC paid $10.3 million to NACCO to terminate its mine management agreement. "This contract mining agreement was terminated effective September 30, 2021. As required under the agreement, NTEC paid the Company a termination fee of $10.3 million." (NACCO Q3 10-Q Filling, https://d18rn0p25nwr6d.cloudfront.net/CIK-0000789933/cf72aeab-ae10-49e2-a968-a2e4549ac9f0.pdf)

Exhibit 3-5
Summary of Amended and Restated Four Corners 2016 Coal Supply Agreement Effective as of July 1, 2018

Summary of Amended and Restated Four Corners 2016 Coal Supply Agreement effective as of July 1, 2018 (the "Agreement")*

Parties	Navajo Transitional Energy Company, LLC (NTEC or Seller) Non-NTEC Buyers (APS, PNM, SRP, TEP) (Buyers)
Effective Date	7/1/2018

[redacted]

Neither the terms of the 2016 Agreement nor the 2018 Agreement were reviewed in the prior audit. The Recitals to the 2018 Agreement includes a number of items such as a payment related to a dispute that arose following the execution of the 2016 Agreement, that were not reviewed.

APS indicated it is in the process of modifying the 2018 Agreement in part to recognize two significant upcoming changes. The first change is APS's announced plans to move to seasonal operation of Unit 5 in 2023. Press reports suggest that this move was for environmental reasons in that such a shift will reduce carbon emissions by 20-25 percent.[15] APS indicated that the move was related to plant economics and should circumstances change, the seasonal operation could be reconsidered. The second change is the sale of Public Service Company of New Mexico's ("PNM") 13 percent share of the Four Corners to NTEC by no later than December 31, 2024.[16,17,18] APS believes that while the current structure of the 2018 Agreement may need to be modestly adjusted, it is fundamentally acceptable in the manner in which the NTEC purchases are handled. To be clear, NTEC coal purchases for NTEC's share of the Four Corners power plant are not covered by that 2018 Agreement. The 2018 Agreement is only between the non-NTEC buyers and NTEC. Clearly, the minimum tonnages for the non-NTEC Buyers need to be reduced but there may be additional concerns as more Four Corners generation becomes market-based and there is increased reliance on NTEC for financing final reclamation.[19]

The average delivered price in both 2019 and 2020 was above $2.80 per MMBtu. As plant personnel indicated, there has been a slight improvement in coal quality over the last two years as reflected in the higher Btu content and lower ash content. The net effect has been a slightly lower delivered price. The better quality coal presumably has been a benefit to plant operations as well. Four Corners purchases of coal during 2019 and 2020 are summarized in Exhibit 3-6 below:

[15] https://dailyenergyinsider.com/news/29516-arizona-public-service-signs-agreement-for-seasonal-operations-at-four-corners-power-plant/#:~:text=News-,Arizona%20Public%20Service%20signs%20agreement%20for%20seasonal%20operations%20at%20Four,in%20the%20fall%20of%202023.

[16] In December 2021, the New Mexico Public Service Commission denied PNM's request to sell its share of Four Corners to NTEC. Multiple reasons were given for this denial including the utility's "failure to identify sufficient generation resources to replace (Four Corners)" https://www.pnmresources.com/~/media/Files/P/PNM-Resources/rates-and-filings/Four%20Corners%20Filing/order-denying-application.PDF

[17] PNM appealed this decision.

[18] Also in December 2021, the New Mexico Public Service Commission denied Avangrid's acquisition of PNM Resources due to concerns over reliability risks and the potential for higher prices and slower development of renewable resources.

[19] Given the denial of PNM's sale of its share of Four Corners, the issues related to NTEC's increased ownership of the Four Corners plant are no longer immediate unless PNM prevails in its appeal.

Exhibit 3-6
Purchases by Four Corners

REPORTED PURCHASES BY FOUR CORNERS

Year	Month	Tons	MMBtu/Ton	Sulfur	Ash	$/Ton	Cents/MMBtu
2019	1	423,385	17.61	0.70	21.70	53.44	303.5
2019	2	413,596	17.59	0.73	24.70	54.53	310.1
2019	3	149,440	16.50	0.70	20.90	50.44	305.8
2019	4	353,842	17.89	0.80	20.80	53.49	299.0
2019	5	361,053	17.91	0.80	20.30	49.15	274.4
2019	6	408,028	18.00	0.80	20.80	50.95	283.1
2019	7	503,995	18.22	0.90	20.60	52.72	289.3
2019	8	506,657	18.21	0.80	21.10	53.69	294.8
2019	9	461,188	18.02	0.80	20.60	40.36	224.0
2019	10	367,067	18.24	0.80	20.00	54.65	299.7
2019	11	400,265	17.89	0.90	21.10	52.73	294.7
2019	12	343,402	17.94	1.00	20.30	49.30	274.9
2019	**TOTAL**	**4,691,918**	**17.92**	**0.82**	**21.11**	**51.29**	**286.3**
2020	1	374,342	21.80	0.80	20.40	64.68	296.7
2020	2	330,730	17.95	0.80	20.20	49.12	273.7
2020	3	252,093	17.90	0.70	20.80	49.09	274.2
2020	4	238,356	18.15	0.80	20.30	53.31	293.7
2020	5	200,487	18.27	0.80	20.40	53.60	293.4
2020	6	351,112	18.22	0.80	21.00	53.45	293.4
2020	7	504,672	18.17	0.70	21.10	52.53	289.1
2020	8	490,061	18.32	0.80	20.90	51.44	280.8
2020	9	555,649	18.22	0.09	21.00	48.00	263.5
2020	10	310,671	18.31	0.80	20.20	48.60	265.5
2020	11	172,512	18.22	0.90	20.30	50.12	275.0
2020	12	389,111	18.34	0.80	19.60	51.52	281.0
2020	**TOTAL**	**4,169,796**	**18.52**	**0.69**	**20.58**	**52.10**	**281.3**

Source: EIA 923 Filings

As shown in the exhibit below, compared to other mine mouth power plants in the southwest, the Four Corners delivered coal price is relatively high. The closest plant to Four Corners, PNM San Juan plant, has delivered prices more than 20 percent lower than the prices to Four Corners.

Exhibit 3-7
Summary of Delivered Coal Prices

DELIVERED COAL PRICES TO MINE MOUTH PLANTS IN THE SOUTHWEST (Cents/MMBtu)

Mine Mouth Plants	2019	2020
Four Corners	286.3	281.3
Bridger	267.7	276.6
Naughton	238.9	243.9
San Juan	199.2	221.7

Source: EIA 923

This analysis is by no means dispositive. The Navajo mine (which supplies Four Corners) is very different from the San Juan mine. Navajo is a large surface mine which has been in operation for decades while the San Juan mine is an underground longwall mine which has only been in operation since 2001. Further, when the active mining area at the Navajo mine moved further away from the power plant, a rail line within the mine property was added to move the coal from the active mining operations to the plant.

The question is whether NTEC could sufficiently reduce production costs in order to make the Four Corners plant more competitive. With NTEC already an owner and potentially a more significant owner, it would certainly behoove NTEC in addition to the other owners for the plant to be as competitive as possible. On the other hand, NTEC benefits from the coal supply agreement pricing. Regardless, the pricing structure in the coal supply agreement, regardless of the existing contract, should be reconsidered.

As noted in the discussion on Cholla, there are a number of utilities considering alternative pricing structures that help to support coal plant operations. For example, as APS is moving towards seasonal operation at Four Corners, a coal producer could also move to seasonal pricing, i.e., have the pricing during the shoulder months at a lower level. To the extent this increases plant utilization, it could serve to reduce fixed costs and improve plant efficiency, i.e., heat rate.

Four Corners' heat rate which reflects plant efficiency is the lowest (best) in each of the four years. While there was no improvement in 2020 as a result of the better coal quality, Four Corners operated at a lower capacity factor which also is a factor in heat rate. The historical performance for the four plants is provided in Exhibit 3-8 below:

Exhibit 3-8
Historical Performance of Mine Mouth Plants

Mine Mouth Plants	2017	2018	2019	2020
	Heat Rate (Btu/kwh)			
Four Corners	10,028	9,259	9,636	10,243
Jim Bridger	10,483	10,512	10,568	10,973
Naughton	10,882	10,958	10,939	11,013
San Juan	10,948	11,312	11,280	11,545
	Capacity Factor			
Four Corners	48.8%	56.1%	66.1%	56.1%
Jim Bridger	62.5%	58.9%	60.5%	56.2%
Naughton	84.3%	89.6%	85.1%	78.7%
San Juan	80.0%	64.2%	64.6%	65.1%

Source: EVA Database

The Four Corners plant does not maintain the plant inventory beyond what is in the surge bins. Under the 2018 Agreement, the Seller is required to maintain a working inventory of 650,000 tons of pre-stripped coal and 100,000 tons in the piles near the plant. Delivery problems are addressed through truck delivery when necessary. Less inventory can be maintained upon agreement with the Operating Representatives.

The Audit Team visited the power plant and the mine unloading area and found it to be well managed. The stockpile layout is particularly helpful in delivering coal with a consistent quality as APS can blend coal from different areas as it is feeding the surge bins.

Natural Gas

Natural gas accounts for the largest source of APS generation. Purchases are reported for five plants on Energy Information Administration ("EIA") Form 923. As shown in Exhibit 3-9 below, natural gas purchases increased significantly between 2018 and 2020. Purchases in 2021 are on pace to be below 2020 levels potentially due to higher natural gas prices.

Exhibit 3-9
Reported Natural Gas Purchases (MCF)

	2018	2019	2020	2021 (7 Months)	2021 Annualized
Red Hawk	25,774,244	32,759,930	39,709,478	23,066,056	39,541,810
West Phoenix	24,287,444	24,718,142	29,685,070	13,875,786	23,787,062
Total CC	**50,061,688**	**57,478,072**	**69,394,548**	**36,941,842**	**63,328,872**
Ocotillo*		5,985,277	6,881,478	3,745,821	6,421,407
Sundance	3,848,320	3,126,645	4,328,449	2,343,094	4,016,733
Yucca	5,002,543	4,418,380	4,567,372	2,251,433	3,859,599
Total CTs	**8,850,863**	**13,530,302**	**15,777,299**	**8,340,348**	**14,297,739**
TOTAL	**58,912,551**	**71,008,374**	**85,171,847**	**45,282,190**	**77,626,611**

* Both CC 'sand CT's
Source: EIA 923

In recognition of volatility in natural gas pricing, APS has an established hedging program for its gas purchases whose primary purpose is to reduce pricing volatility. As APS noted in its response to Staff data request 7.6 (g), the "APS Hedge Program provides financial hedging of the volatility in gas prices using approved trading instruments. Positions are generally transacted using fixed for floating swaps with delivery in a specified future delivery month. As that delivery month approaches, the financial positions settle at the index price associated with the location and delivery month. After settlement of the financial hedging transaction, APS (purchases) physical gas for the prompt month at current market prices that should reflect the index price received for the financial hedge."

The hedging policy defines the quantity of energy to be hedged as follows:[20]

- The first forward four full calendar quarters will be hedged at 85 percent of the forecasted energy need, with a plus or minus 5 percent tolerance band at all times.
- The subsequent four calendar quarters will be hedged at 55 percent of the forecasted energy need, with a plus or minus 5 percent tolerance band at all times.
- For year three, the initial hedge transacted will be for the third quarter only and will be purchased to meet the requirement of 45 percent of the annual forecasted energy need, with a plus or minus 2 percent tolerance band.
- For year four, only annual strips will be purchased to satisfy the target of 30 percent of the annual forecasted energy need, with a plus or minus 2 percent tolerance band.
- For year five, only annual strips will be purchased to satisfy the target of 15 percent of the annual forecasted energy need, with a plus or minus 2 percent tolerance band.

This type of hedging program is consistent with the hedging programs of other utilities.

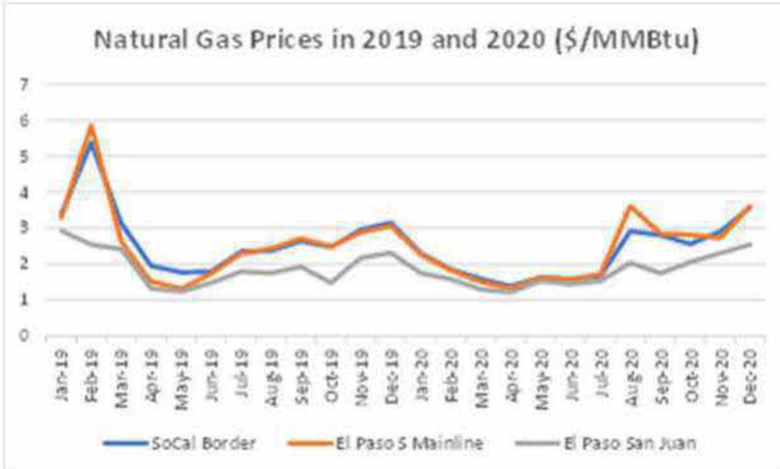
In 2020, APS elected to temporarily suspend its hedging for years 4 and 5 "given the economic uncertainties and considerations of clean energy standards across the Western Region."[21] This was a reasonable decision for the reasons APS indicated.

That being said, there are reasons for increased natural gas price volatility in the future. As such, the Audit Team recommends that the components of the APS Hedge Program be reviewed periodically, but no less than every two years, to determine what if any changes should be made to address price uncertainty.

Prices paid for gas are tied to the commodity price for natural gas. As shown in Exhibit 3-10 below, natural gas prices at the relevant hubs in 2019 and 2020 displayed some volatility but with the exception of February 2019 were consistently below $4 per MMBtu.

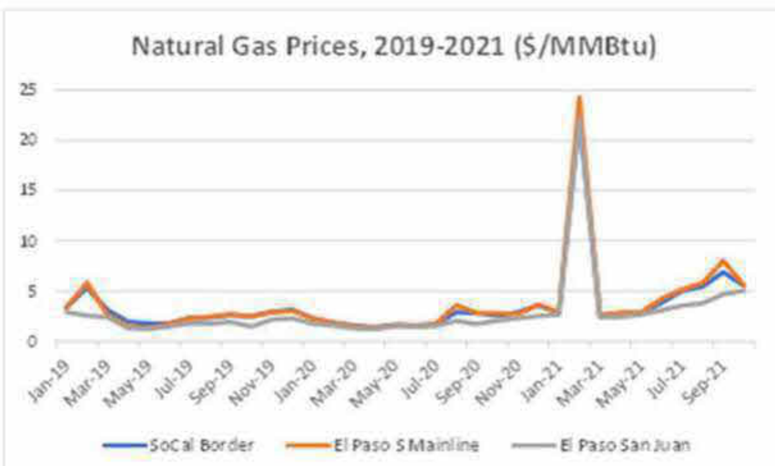
[20] See the response to Staff data request 5.3.
[21] See the response to Staff data request 1.11.

Exhibit 3-10
Natural Gas Purchases in 2019 and 2020



This changed in 2021 as shown in Exhibit 3-11 below. Natural gas prices in February 2021 increased above $20 per MMBtu and have been at above three-year high since mid-year.

Exhibit 3-11
Natural Gas Purchases from 2019 through 2021



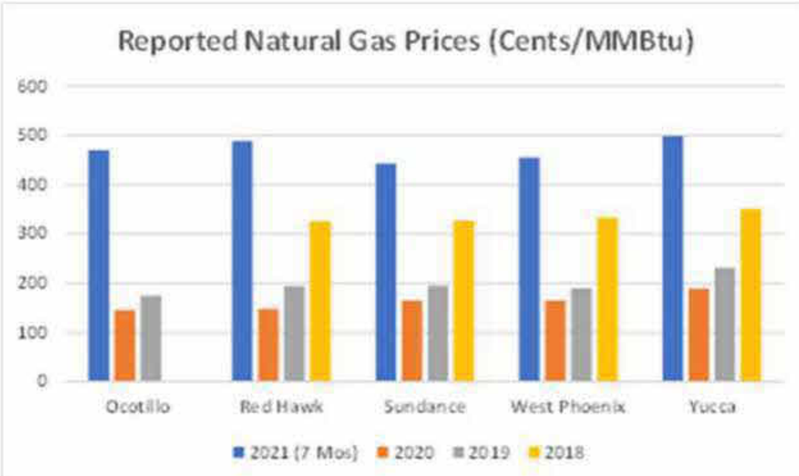
APS attributes the spike in 2021 natural gas prices to several factors, including:

- The February freeze in the southwest which resulted in regional supply cuts.
- Supply reductions in August/September related to Hurricane Uri.
- Hotter regional temperatures.
- Pipeline constraints including a mid-August L2020 pipeline exposure which reduced availability of El Paso South Mainline gas.
- Reduced regional storage levels.
- Reduced production of associated gas as a result of low oil production.

To this list, the Audit Team would add that the drought in the southwest, which reduced hydro availability and resulted in significantly higher global Liquefied Natural Gas ("LNG") prices, which diverted natural gas supply into this market.

As shown in Exhibit 3-12 below, the spike in natural gas prices in 2021 has resulted in about a 250 percent increase year-over-year in the reported delivered natural gas prices to the EIA on Form 923.

Exhibit 3-12
2021 Spike in Reported Natural Gas Prices



APS notes the costs it reports to EIA are the "commodity plus pipeline costs" which includes the commodity costs plus variable pipeline costs including usage taxes, pipeline transport costs, shrinkage charges and other daily usage fees." APS noted "the pipeline costs are allocated to the natural gas plants … based on monthly MMBTU burns."

The Audit Team attempted to benchmark natural gas prices paid by APS with other gas-fired plants in the southwest. APS determined that the reporting of natural gas procurement costs varies among utilities thereby making this comparison not particularly meaningful.

Nuclear

APS operates the 1,146 MW Palo Verde nuclear plant with three units, two of which started operations in 1986. The third unit started in 1988. Palo Verde's owners include APS (29.1 percent), SRP (17.5 percent), El Paso (15.8 percent), Southern California Edison (15.8 percent), PNM Resources (10.2 percent), Southern California Public Power Authority (5.9 percent), and Los Angeles Department of Water and Power (5.7 percent). An aerial view of Palo Verde is shown in the exhibit below.

Exhibit 3-13
Aerial View of Palo Verde

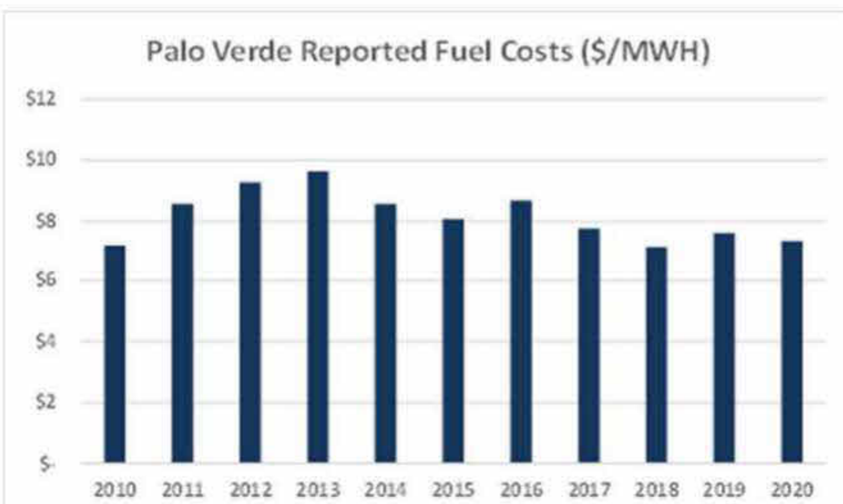
The Palo Verde owners are shown in Exhibit 3-14 below. Six owners account for approximately 99 percent of the plant.

Exhibit 3-14
Summary of Palo Verde's Ownership

Owner	Ultimate Parent	Operating Capacity Ownership
Arizona Public Service Co.	Pinnacle West Capital Corp.	29.10%
Salt River Project Agricultura	Salt River Project Agricultura	17.49%
El Paso Electric Co.	JPMorgan Chase & Co.	15.80%
Southern California Edison Co.	Edison International	15.80%
Public Service Co. of NM	PNM Resources Inc.	10.20%
Los Angeles Dept Water & Power	Los Angeles Dept Water & Power	9.66%
Imperial Irrigation District	Imperial Irrigation District	0.38%
Riverside City of	Riverside City of	0.32%
Vernon City of	Vernon City of	0.29%
Pasadena City of	Pasadena City of	0.26%
Glendale City of	Glendale City of	0.26%
Burbank (CA)	Burbank (CA)	0.26%
Colton City of	Colton City of	0.06%
Azusa (CA)	Azusa (CA)	0.06%
Banning (CA)	Banning (CA)	0.06%

The reported fuel costs for Palo Verde have been somewhat volatile over the last decade as shown in Exhibit 3-15 below:

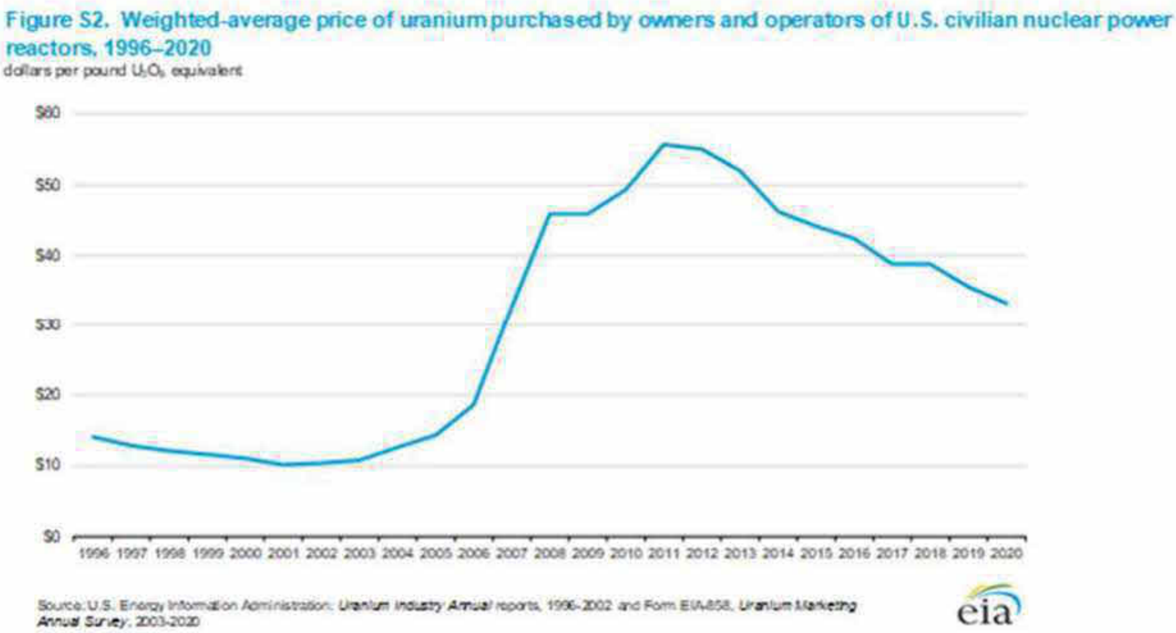
Exhibit 3-15
Palo Verde Reported Fuel Costs



APS explained that nuclear fueling is a complicated enterprise. From an accounting perspective, the full nuclear assembly includes costs related to the uranium, conversion, enrichment, fabrication, Arizona use tax, and engineering. In response to DR-4.1, the Company explained that these costs are typically incurred over a two-year period and then amortized upon insertion of the assembly over the two or three 18-month cycles. Further, only a portion of the fuel assembles are replaced during each refueling. The Company believes that the reported nuclear fuel costs in any year reflect costs incurred over a 6.5-year period.[22] This is further complicated by the use of average unit cost accounting which further delinks the annual reported costs to the cost performance in any given year.

In the same DR response, APS provided color as to the volatility in the reported Palo Verde fuel costs. APS noted uranium prices increased significantly in the 2006-2008 period due to the entrance of financial institutions and traders entering the market. Uranium prices peaked around \$95 per pound before falling significantly. In mid-2010, uranium prices hit a new low around \$56 per pound before climbing through \$69 per pound. The magnitude 9.0 Fukushima earthquake in March 2011 and the attendant nuclear moratorium in Japan increased uranium availability as some existing inventory was released. The net result was a steady decline in uranium prices which bottomed out in the \$27-\$28 per pound through most of 2017 until 2019. The EIA, which reported average prices of uranium, shown in Exhibit 3-16 below, did not track these numbers exactly but they corroborate the represented trends:

Exhibit 3-16
Average Uranium Prices



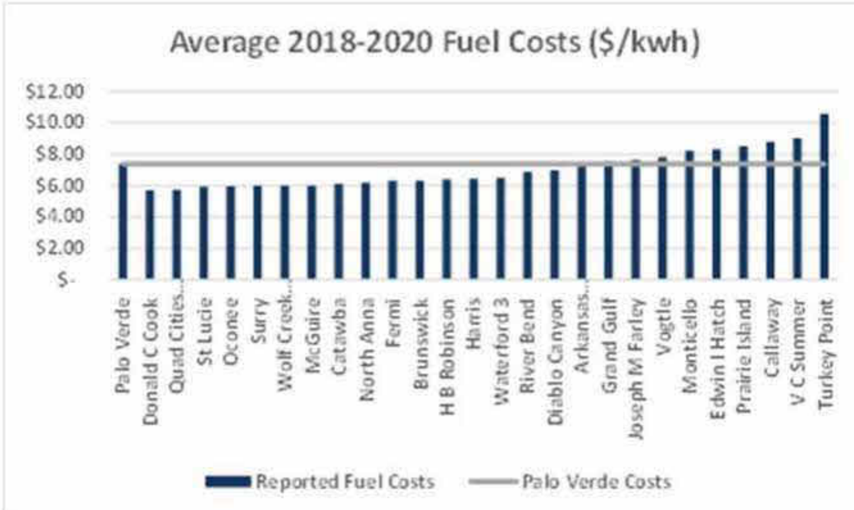
Source: https://www.eia.gov/uranium/marketing/, Table S1b

APS also noted that the unit costs (\$/MWH) in any year reflect capacity factor.

As shown in the exhibit below, in the last three years, Palo Verde ranks 18 highest out of the 26 regulated nuclear plants:

[22] See the response to Staff data request 4.1.

Exhibit 3-17
Average Nuclear Fuel Costs – 2018 through 2020



APS offered interesting insights as to why this might be the case. APS noted that since Diablo Canyon is slated for decommissioning, fuel purchase costs may be lower due to the unwinding of commitments. APS also noted that a number of the units are part of multi-unit fleets (namely Entergy includes Waterford 3, River Bend and Arkansas Nuclear, NextEra includes Turkey Point and St. Lucie, and Dominion includes Surry, North Anna and VC Summer) that potentially benefit from volume price discounts in the procurement and enrichment processes. Of course, this does raise the question as to whether coordination with other parties regarding its nuclear fuel procurement should be considered.

4 FINANCIAL AUDIT OF THE POWER SUPPLY ADJUSTOR MECHANISM AND RELATED DOCUMENTATION

Organization

The section of the report concerning our review of APS's PSA filings audit is organized into the following sections:

- Standard Review Requirements
    - Coal-Fueled Plants Generating Power for APS
    - APS Jointly Owned Generation
- PSA Deferrals
    - Simulation Models
    - System Dispatch
    - Off-System Sales
    - Energy Imbalance Market
    - Energy Storage
    - Review Related to Coal Order Processing
- Invoices for Coal Purchases
- Freight Vouchers
- Fuel Analysis Reports
- Retroactive Escalations
- Review Related to Station Visitation and Coal Processing Procedures
- Coal Receiving
- Cholla Plant
- Four Corners Plant
- Navajo Generating Station
- Coal Sampling
- Review Related to Fuel Costs

- Review Related to Purchased Power
- Review Related to Service Interruptions and Unscheduled Outages
- Capacity Factors and Equivalent Availability Factors
- PSA Filings, Supporting Workpapers and Documentation
- Review Related to Hedging Activities
- Chemicals and Reagents
- Emission Allowances
- Changes to Fuel, Purchased Power Procurement and Emission Allowance Procurement
- External and Internal Audits
- Findings and Recommendations

Standard Review Requirements

The Audit Team's review of utility fuel and purchased power accounting and cost recovery procedures includes, but is not limited to, a review of the following standard items:

(1) Procedures for accounting for fuel receipts, testing, and payments;

(2) Procedures for weighing, testing and reporting coal burned;

(3) Procedures for recording purchases and interchanges;

(4) Procedures for accounting treatment of emission allowances; and

(5) Procedures for calculating the PSA rate.

Coal-Fueled Plants Generating Power for APS

With regard to the coal-fired plants that generate power for APS, the Company's rights to (1) access information, and (2) to review plant operation performance and related costs are summarized as follows:[23]

Cholla Plant – APS is a partial owner, but operates the Cholla Plant so the Company has full access to operational performance and related costs.

Four Corners Plant – APS is a partial owner, but operates the Four Corners Plant so the Company has full access to operational performance and related costs.

Navajo Generating Station – APS was a partial owner, but the SRP operated the Navajo Generating Station until it closed near the end of 2019. Upon request, APS had full access to operational performance and related costs.

APS Jointly Owned Generation

As noted above, APS is a partial owner of Cholla and Four Corners and had been a partial owner of the Navajo Generating Station until it closed in 2019. Specifically, APS was a joint owner of

[23] See the response to Staff data request 1.22.

five power plants during the review period. The five jointly owned power plants are comprised of the following:[24]

- Palo Verde Generation Station (operated by APS).
- Four Corners Power Plant (operated by APS).
- Cholla Power Plant (operated by APS).
- Yucca Power Plant (operated by APS)
- Navajo Power Plant (closed in 2019 and was operated by SRP)

According to the response to Staff data request 1.25, the fuel costs at the jointly-owned generation plants are shared by the plant owners in accordance with contractual agreements and by the amount of fuel used.

Larkin reviewed APS's procedures for accounting for fuel purchases and inventory accounting, which were provided in APS's response to Staff data request 1.36.[25] Specifically, the Company provided three confidential attachments related to APS's fuel purchasing and inventory accounting process, which are summarized as follows:

<u>Coal Settlements Procedures</u>

The coal settlements procedures were provided in confidential attachment APS21FA00249 which is 144 pages. In the Purpose and Applicability section of this document, it states:

> The purpose of this procedure is to identify the process for which all valid fuel related invoices are accurately captured and validated prior to approvals and payment. The Fuels Invoice Verification and Approval Procedure completes the next step of invoice approvals and payment settlement. All valid shipments are reconciled with plant reports on a timely basis. Discrepancies are communicated to the plant or freight shipper and monitored through resolution. All Back Office settlement functions are performed independently through a series of internal reports and external systems and suppliers.
>
> The Energy Analyst receives invoices from coal suppliers. In addition, internal reports are received from each plant and from outside vendors to reconcile and independently validate information shown on invoices. Invoice validation is done through a recalculation of the invoice based on internal and external reports. Checklists are also maintained to indicate that all major invoice categories (volume and pricing) have been validated and reconciled. All invoices, validation worksheets and checklists are reviewed by Energy Settlement Supervisor and Fuel Procurement team prior to being sent for payment.

<u>Gas Storage Accounting Procedures</u>

The gas storage accounting procedures were provided in confidential attachment APS21FA00250 which is 20 pages. In the Purpose and Applicability section of this document, it states:

[24] See the response to Staff data request 1.25.

[25] These procedures were also requested in Staff data request 1.21.

The procedure details the process for Back Office Reporting ("BOR") to record monthly gas storage activity to the general ledger. Arizona Public Service Company ("APS") has a contract with [redacted]

The following costs are associated with the [redacted] contract activity:

- Delivered Commodity Cost (Purchase Price) and Withdrawal Cost – the physical cost of gas injected and withdrawn from storage.

- Fixed Demand Charge – fixed monthly fee that fluctuates based upon season and adjusted annually per contract.

- Injection and Withdrawal Fees – variable fees associated with gas flowing into (injections) and out of storage (withdrawals).

- Injection and Withdrawal Overrun Fees – variable fees associated with injection and/or withdrawals exceeding the daily maximum volumes.

Variable pipeline transport cost assessed by El Paso Natural Gas ("EPNG") or Transwestern ("TW") for moving physical gas to storage on behalf of APS.

- These costs are in addition to the fees associated with the Kinder Morgan contract billed separately by EPNG and TW to APS.

The following costs are captured in the Open Access Technology International ("OATI") webTrader system in the gas storage Weighted Average Cost of Gas ("WACOG"):

The purchase and withdrawal cost of gas into and out of storage.

- This is not recorded as part of the gas storage journal entry.
- Accounting adjustments are entered by BOR into OATI to capture the current month net storage injections and withdrawal.
- The net monthly activity is then captured as part of the Monthly Gas Interchange journal entry at estimate at final and recorded to inventory.

Variable injection and withdrawal fees associated with daily activity.

- Not accrued for at estimate.
- At final the Back Office Settlements ("BOS") charges the fee payment directly to inventory.

Variable EPNG and TW transport costs associated with transporting gas to storage.

- Accrued for at estimate and final and recorded to inventory as part of the gas storage journal entry.
- The costs are included in the EPNG and TW variable transport invoice which is reported as part of the Gas Fuel Expense Entry at estimate and final.
- The portion related to storage captured in the WACOG (inventory) is excluded from the gas fuel cost entry which is expensed.
- In the gas fuel expense entry this is shown as a fuel reduction to the variable expense recorded to fuel.
- At final BOS settles the total variable transport cost to the liability account.
- The gas storage entry records the liability associated with the EPNG and TW transport with an offset to inventory.

The following are not captured in OATI gas storage WACOG:

Fixed Demand Charge

- At estimate accrued for as part of the gas storage journal entry and expensed.
- At final BOS charges the payment directly to the income statement.
- Journal entry not completed at final.

The variable overrun fees associated with daily injections/withdrawals exceeding daily maximums.

- Not accrued for at estimate.
- At final BOS charges the fee payment directly to the gas storage inventory account.

<u>Gas Settlements Procedures</u>

The gas storage accounting procedures were provided in confidential attachment APS21FA00251 which is 92 pages. In the Purpose and Applicability section of this document, it states:

The Natural Gas Settlements process ensures that physical and financial transactions are accurately and completely captured and settled. Back Office Settlements completes the procedures below to ensure APS internal systems and reports agree to external systems and suppliers, and all invoicing (payables and receivables) is processed and settled in a timely manner with the counterparties and brokers.

All valid transactions are audited and reconciled on a timely basis. Transaction discrepancies are analyzed, verified and communicated to appropriate personnel. Internal and external disputes are tracked and monitored through resolution.

All Back Office settlement functions are performed independently of the Front Office.

This document covers the settlement in Section 6, which is broken out into the following sections:

- Section 6.1 – Daily Audits – Confirm Pipeline Delivery
- Section 6.2 – Weekly Audits – Confirm Pipeline Imbalances
- Section 6.3 – Monthly Audits
- Section 6.4 – Counterparty Checkout
- Section 6.5 – Physical Gas Invoicing
- Section 6.6 – Options and Premiums
- Section 6.7 – Audit/Reconcile Financial Transactions
- Section 6.8 – Daily and Monthly Checklists

Based on our review of these documents, we conclude that APS's processes for fuel purchases and inventory accounting is comprehensive and appropriate.

The Company's procedures for coal sampling are discussed in the section of this chapter titled "Review Related to Station Visitation and Coal Processing Procedures."

PSA Deferrals

Larkin requested that APS identify any fuel amounts (by account) that were deferred that affected calendar years 2019 and 2020 as well as January 2021. In its response to Staff data request 1.26, the Company provided confidential attachment APS21FA00072, which summarized PSA related deferrals for 2019, 2020 and January 2021. The deferral amounts that affected calendar year 2019 are summarized in the exhibit below:

Exhibit 4-1
Fuel and Purchased Power Deferrals Through the PSA – Calendar Year 2019

Description	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Fuel Deferral - Amounts in $000's													
Fuel Expense Deferral - Total Gross Deferral	$ 10,452	$ 19,264	$ (80)	$ (16,985)	$ (24,230)	$ (25,278)	$ (12,022)	$ (17,819)	$ (5,612)	$ 4,647	$ (11,339)	$ (15,172)	$ (94,174)
Amortization of Deferred Fuel Recovery/(Refund)	$ 10,384	$ 416	$ 2,685	$ 3,040	$ 3,179	$ 4,342	$ 5,373	$ 5,618	$ 4,457	$ 3,453	$ 2,959	$ 4,617	$ 50,523
Total Net Fuel Deferral	$ 20,836	$ 19,681	$ 2,604	$ (13,945)	$ (21,050)	$ (20,936)	$ (6,649)	$ (12,201)	$ (1,156)	$ 8,100	$ (8,380)	$ (10,555)	$ (43,651)
O&M Deferral - Amounts in $000's													
Chemical Expense Deferral	$ (124)	$ (389)	$ 357	$ (326)	$ (192)	$ 61	$ (423)	$ 81	$ (106)	$ (314)	$ (415)	$ (97)	$ (1,886)
SO2 Expense Deferral	$ (2)	$ (2)	$ (2)	$ (2)	$ (2)	$ (3)	$ (3)	$ (3)	$ (3)	$ (2)	$ (2)	$ (2)	$ (28)
Amortization of Deferred O&M Recovery / (Refund)	$ (129)	$ 2	$ (35)	$ (37)	$ (38)	$ (52)	$ (56)	$ (54)	$ (43)	$ (34)	$ (33)	$ (55)	$ (563)
Total Net O&M Deferral	$ (255)	$ (389)	$ 320	$ (365)	$ (232)	$ 7	$ (483)	$ 23	$ (152)	$ (350)	$ (449)	$ (153)	$ (2,478)
Source: Staff Data Request 1.26													

As shown in the above exhibit as it relates to fuel deferrals, for 2019 the Company reflected fuel expense deferrals totaling ($94.174 million), amortization of deferred fuel recovery totaling $50.523 million for a total net fuel deferral of ($43.651 million). As it relates to O&M deferrals in 2019, the Company reflected chemical expense deferrals totaling ($1.886 million), emission allowance deferrals totaling ($28,000) and amortization of deferred O&M refunds totaling ($563,000) for a total net O&M deferral of ($2.478 million).

The deferral amounts that affected calendar year 2020 and January 2021 are summarized in the exhibit below:

Exhibit 4-2
Fuel and Purchased Power Deferrals Through the PSA – Calendar Year 2020 and January 2021

Description	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Fuel Deferral - Amounts in $000's													
Fuel Expense Deferral - Total Gross Deferral	$(25,143)	$ (11,075)	$ 19,590	$ 42,531	$ (20,611)	$ (27,766)	$ 10,289	$ 27,103	$ (19,302)	$ 35,771	$ (37,984)	$ (26,601)	$ (33,198)
Amortization of Deferred Fuel Recovery/(Refund)	$ 3,367	$ (4,913)	$ (1,108)	$ (889)	$ (1,377)	$ (1,536)	$ (1,988)	$ (2,096)	$ (1,583)	$ (1,304)	$ (1,011)	$ (1,178)	$ (15,615)
Total Net Fuel Deferral	$(21,777)	$ (15,988)	$ 18,482	$ 41,642	$ (21,988)	$ (29,302)	$ 8,302	$ 25,007	$ (20,885)	$ 34,467	$ (38,995)	$ (27,780)	$ (48,813)
O&M Deferral - Amounts in $000's													
Chemical Expense Deferral	$ (486)	$ (529)	$ 316	$ (254)	$ 739	$ 150	$ 197	$ 255	$ (448)	$ (67)	$ 40	$ 61	$ (26)
SO2 Expense Deferral	$ (2)	$ (2)	$ (2)	$ (2)	$ (3)	$ (3)	$ (4)	$ (4)	$ (3)	$ (2)	$ (2)	$ (2)	$ (29)
Amortization of Deferred O&M Recovery / (Refund)	$ (40)	$ 685	$ 201	$ 183	$ 293	$ 318	$ 413	$ 437	$ 337	$ 279	$ 213	$ 249	$ 3,568
Total Net O&M Deferral	$ (529)	$ 155	$ 515	$ (73)	$ 1,030	$ 465	$ 606	$ 688	$ (114)	$ 210	$ 251	$ 308	$ 3,512

Description	January 2021
Fuel Deferral - Amounts in $000's	
Fuel Expense Deferral - Total Gross Deferral	$ 18,928
Amortization of Deferred Fuel Recovery/(Refund)	$ (1,153)
Total Net Fuel Deferral	$ 17,775
O&M Deferral - Amounts in $000's	
Chemical Expense Deferral	$ (19)
SO2 Expense Deferral	$ (2)
Amortization of Deferred O&M Recovery / (Refund)	$ 242
Total Net O&M Deferral	$ 221
Source: Staff Data Request 1.26	

As shown in the above exhibit as it relates to fuel deferrals, for 2020 the Company reflected fuel expense deferrals totaling ($33.198 million), amortization of deferred fuel recovery totaling ($15.615 million) for a total net fuel deferral of ($48.813 million). As it relates to O&M deferrals in 2020, the Company reflected chemical expense deferrals totaling ($26,000), emission allowance deferrals totaling ($29,000) and amortization of deferred O&M refunds totaling $3.568 million for a total net O&M deferral of $3.512 million. For January 2021, the Company reflected fuel expense deferrals of $18.928 million, amortization of deferred fuel recovery of ($1.153 million) for a total net fuel deferral of $17.775 million. As it relates to O&M deferrals in January 2021, the Company reflected a chemical expense deferral of ($19,000), emission allowance deferrals totaling ($2,000) and amortization of deferred O&M refunds totaling $242,000 for a total net O&M deferral of $221,000.

With regard to our request that APS identify the accounts in which deferrals are recorded, in its response to Staff data request 1.26, the Company stated that it does not record fuel cost deferrals by individual line item or account. Rather, in accordance with the PSA POA, APS defers expenses that differ from those included in the base cost of fuel and purchased power. Specifically, page 6 of the POA states the following with regard to the base cost of fuel and purchased power:

> An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. 76295 set the base cost at $0.030168 per kWh effective on August 19, 2017.

We verified that the base cost of fuel and purchased power of $0.030168 per kWh is reflected in the calculations in the Company's monthly PSA filings for the review period. No exceptions were noted.

Simulation Models

Larkin requested that APS identify the system simulation model(s) it uses to develop its forecasts of fuel and purchase power volume requirements. In its response to Staff data request 1.56, the Company identify the following two system simulation models that it uses for forecasting fuel and purchased power volumes and the associated expenses:

- The Aurora model, which was developed by Energy Exemplar, is used by Resource Planning and Analysis. This model develops forecasts based on a long-term focus (i.e. 6 to 20 years).
- The RTSim model, which was developed by Simtec, is used by Marketing & Trading Business Support. This model develops forecasts based on a mid-range focus (i.e., 1 to 5 years).

In order to obtain an understanding of how these simulation models function, we requested that APS conduct a walkthrough of the Aurora and RTSim model simulation models.[26] The requested walkthrough was conducted via a Microsoft Teams meeting on November 12, 2021 and focused primarily on the RTSim model.

With regard to the Aurora model, APS stated that while the inputs are similar to that of the RTSim model, the Aurora model does not track fixed and variable costs. As noted above the Aurora model develops forecasts with a focus on the long term (6 to 20 years). During the November 12, 2021 walkthrough, the Company stated that due to Aurora forecasting longer run times than the RTSim model, the Aurora model is used more for integrated resource planning.[27]

[26] See the response to Staff data request 7.4.
[27] In its response to Staff data request 1.38, APS provided an excerpt from its 2020 Integrated Resource Plan which describes the Company's load forecasting methods.

For its walkthrough of the RTSim model simulation model, the Company used a confidential PowerPoint presentation, which included the following description of the RTSim model:

> RTSim (Real-Time Simulation) is a type of generation simulation model written specifically for use by a company with generation which is operating in a market. RTSim will provide a realistic simulation of an electric generating system for a period of a month to years. RTSim will find higher probability, lower risk, market transactions, maintenance schedules, emission compliance strategies and fuel procurement schedules while maintaining reliable, reasonable cost service to the traditional regulated market sector.

APS stated that it has been using RTSim for over 20 years and that it is also used by other utilities as well.[28] APS uses RTSim for fuel and purchased power time horizons of one month to five years and the model provides probabilistic modeling on forced outages and is also a production cost model designed to find the optimum unit commitment at the lowest cost using the following general constraints:

- Spinning Reserve
- Cycling Restraints
- Fuel Burn Limits
- Load Requirements
- Unit Up and Down Time Limits
- Minimum and Maximum Unit Capacities

The average number of RTSim model updates is three to six times per year and the average number of production assumption updates is 20 to 25 times per year.

The general structure of the RTSim model is comprised of the following eight modules:

- Market:
  - Power Prices
  - Purchase & Sales Transactions
  - Solar PPA Contracts
- Fuel:
  - Natural Gas Prices
  - Fuel Contracts
- Run:
  - Loads
  - Reserve Requirements
- Outage:

[28] Other utilities using RTSim include: [redacted]

- Planned Outages

- Hydro Module:
  - Wind Resources
  - APS-Owned Solar
  - Battery Storage
- Emissions
- Unit:
  - Capacities and Operating Assumptions
- Schedule Module:
  - Seasonal Capacities
  - Annual Pricing & Forced Outage Rates
  - Heat Rates I/O Schedules

Under the Unit Commitment concept, RTSim connects units to the grid on an economic basis under the following constraints: (1) spinning reserve, (2) thermal units, (3) minimum up and down time, (4) must run requirements, (5) environmental constraints, and (6) fuel constraints.

RTSim performs the Unit Commitment on the following basis:

1. Schedule integrated commitment on a day ahead basis whereby the concept is to deploy units from least to most expensive cost in which the following stacking order is considered:
   - Must run units and fixed transactions
   - Renewables
   - In the money call options
   - Generating units
   - Day ahead purchases and sales opportunities (3-7 days)
2. Calculate integrated hourly commitment:
   - Mid-day forced outages
   - Quick start units
   - Hourly spot market (purchases or sales)

The RTSim model inputs include: (1) forward price calculation (populated by Tranz.Net), (2) monthly fuel prices, which are supplied by the Fuels Department, (3) outage schedule process (planned and maintenance), (4) renewable generation modules (i.e., profiles), and (5) GMIS Power Manager. During the November 12, 2021 Microsoft Teams meeting, the Company stated that many of the inputs come from outside the analytics team (i.e., from other departments).

With regard to the fuel and purchased power expense process, the RTSim model uses the Balance of Year ("BAL") Report Writer application, which reflects the following RTSim model outputs: monthly forecast data and rating period data plus (1) actual results, (2) fixed cost data, (3) variable cost data, (4) mark-to-market data, and (5) coal contract minimum expenses. The

BAL report also includes own load and off-system fuel and purchased power expense and volumes by resource.

The use of the RTSim model is summarized as follows:

- Input to the annual PSA balance/forecast (but does not calculate the PSA rate)
- Fuel and purchased power strategies
    - BAL report (natural gas burns and spot purchase volumes)
- Long-term contract evaluation
    - Natural gas transport, coal contracts, purchase power agreements and term sales evaluations
- Financial updates
    - Monthly current work plan (CWP) report
    - Quarterly updates (budget and long-term forecast)
    - Forecast base fuel rate used in rate setting
- Plant operational studies
    - Asset valuation
- Planned outage development
    - System cost impact support
- Fuel variance analysis – budget vs. actual operations
- Future generator outage analysis
- Ad hoc requests involving simulations
    - Plant improvements

As part of its presentation during the November 12, 2021 walkthrough, APS provided its actual year-to-date (through September 2021) Resource Mix Variance, which is replicated in the exhibit below:

Exhibit 4-3
Year-to-Date (through September 30, 2021) Resource Mix Variance

Generating Facility	Actual	Budget	Variance
Palo Verde	32.9%	32.5%	0.5%
Renewables	8.5%	9.0%	-0.5%
Cholla	6.4%	5.5%	0.9%
Four Corners	16.5%	18.5%	-2.0%
Ocotillo	2.4%	4.1%	-1.7%
Redhawk	20.0%	18.8%	1.2%
Saguaro	0.3%	0.5%	-0.2%
Sundance	1.4%	0.8%	0.7%
West Phoenix	10.9%	9.5%	1.4%
Yucca	0.6%	0.8%	-0.2%
Source: Staff Informal Data Request 3.1, Attachment APS21FA00329			

As shown in the above exhibit, through September 2021, there were no budget to actual resource mix variances greater than 2 percent, which occurred at Four Corners.

<u>Conclusion</u>

As noted above, APS has used the RTSim model for over 20 years and the Company asserted that it is happy using this forecasting model, primarily for its speed coupled with its accuracy. We concur that the RTSim model provides APS with a reasonable means to develop its forecasts of fuel and purchased power volume requirements.

System Dispatch

Day-ahead planning affects system dispatch decision as well as short-term energy transactions, such as those in the energy imbalance market (discussed in more detail below). We asked APS to identify models used by day-ahead traders and for the correct dispatch of generating resources. In response to Staff data request 1.57, the Company stated that Power Costs, Inc. ("PCI") provides a system optimization solution that is used by Marketing & Trading business support, day-ahead and real-time traders. In its response to Staff data request 1.42, the Company provided the following process for how it dispatched its generating units during the 2019, 2020 and January 2021 review period, which is completed within the PCI system optimization solution[29]:

[29] See the response to Staff data request 8.2(a).

> APS optimizes the use of its resources to serve its customers in the most affordable manner possible, while maintaining grid reliability. The process begins by forecasting the load on a day-ahead basis. The load forecast is entered into a unit commitment and dispatch model (PCI GenTrader®/GenPortal®) that determines the most economic unit commitment plan for serving load, taking into account generating unit capabilities, intermittent resource production forecasts (e.g., wind and solar), fuel prices, contractual requirements, and transmission constraints. This commitment plan shows the units to be committed each hour, their projected loading level and the quantity of natural gas to be scheduled.
>
> As part of the process, the model calculates prices for blocks of energy to help determine if it would be cheaper to buy power from the market rather than to run generating units. The day-ahead trader compares these calculated block energy prices with actual power prices being offered in the market, then purchases either on-peak or off-peak blocks of energy, if economical. The model also calculates the breakeven price for making sales out of the Company's generating resources, after taking into account native load and any other pre-existing power sales commitments. If economical, the day-ahead trader will make power sales in the market.
>
> The day-ahead commitment plan is turned over to real-time operations to manage in the intraday markets. The real-time traders update the load and available resource forecasts and re-run the unit commitment and dispatch model to fine-tune the commitment plan. They also check the intraday market to make purchases and sales of power to further optimize the system.
>
> Every hour, APS submits the hourly resource plan to the CAISO Energy Imbalance Market (EIM) for further sub-hourly optimization across the EIM footprint. Once into the operating hour, EIM sends dispatch targets to APS resources based on resource costs and parameters to optimize resources in 5-minute intervals. Through calculated cost curves of each unit, market determines which generators should be incremented, decremented, committed (start) and de-committed (shutdown) as part of a greater EIM footprint solution. While considering available transmission resources, fuel supplies, and reliability needs, APS participates in both the 5- minute and 15-minute markets while maintaining the NERC required reserves and system stability requirements. Each of these markets use dynamic meter and load data as well as 5-minute renewable forecasting to dispatch all participating units with the goal of reducing the production cost for APS customers and the greater EIM footprint.
>
> As the final step in this process, the real-time traders issue the commitment instructions to generating units as needed to meet load and sales commitments. Additionally, they respond to dynamic changes by updating the plan as needed for generating unit or transmission outages and forecast updates; continuously optimizing usage of available resources.

In addition to the process described in the passage above, in its response to Staff data request 1.92, APS provided a confidential 19-page document titled "Procedure: PCI Optimization and

Base Schedule Submission", which the Company stated is the PCI system optimization solution referenced in the response to Staff data request 1.57.[30]

We asked how APS considers weather and the availability and generation from renewable resources (e.g., solar) when determining the correct dispatch of generating resources. In response to our inquiry, the Company stated that each hour, APS real-time traders refresh the forecasted output of each renewable resource, including wind, solar and biomass. The real-time traders then update the renewable profiles to re-optimize the unit commitments and dispatch to account for the variability of renewable resources that are driven by weather. In addition to the updated unit commitments, a revised customer load forecast is entered in order to ensure that the latest weather forecast has been accounted for.[31]

We also asked the Company how it evaluates the effectiveness of its short-term modeling and forecasting (i.e., such as days during summer, shoulder periods, and winter) versus actual results. In its response to Staff data request 8.2(d), the Company stated that it evaluates the effectiveness of its short-term modeling in the following ways:

- Reviewing monthly budget fuel variances, which includes variances driven by outages, market and gas prices, load deviations and replacement costs.
- Tracking monthly metrics that compare DA renewable and load forecasts to actual performance.
- Generation, Marketing and Trading meet on a monthly basis to discuss unit operating parameters which are dynamically managed through the different seasons.
- Tracking all deviations in unit performance and comparing the unit operating targets to actual MW generation output.
- Tracking balance targets for each hour to ensure reliability of the system to each operating hour as well as overall flexibility of the system from hour to hour.

As it relates APS implementing any changes to its system dispatch model during the review period, in its response to Staff data request 8.2, the Company stated that it follows a continuous improvement philosophy and is constantly working on changes to its dispatch model in order to reduce costs and/or improve operational efficiency. As a result, APS made substantial changes to its system dispatch model during the period January 2019 through January 2021. In addition, APS implemented several new assets during the review period which represented a significant change to the system dispatch model. The Company provided a confidential PowerPoint presentation titled "Upcoming Projects & Accomplishments 2021-2-22" (dated January 14, 2021), which listed improvement and/or enhancement projects that impacted the system dispatch model. APS stated that these improvements fell into the following categories:

- Improving natural gas forecasting and gas management accuracy.
- Improving the accuracy of load forecasting.

[30] See the response to Staff data request 8.2(b).
[31] See the response to Staff data request 8.2(c).

- Adding automation to improve operational efficiency and reduce human performance mistakes.
- Improving interactions with external markets.

APS asserted that these improvements impacted the accuracy of the system dispatch model either directly or as dynamic inputs into the model. In addition to the changes implemented by APS, the Company stated that there were also changes to the system dispatch model that were initiated by PCI as well as the markets in which the Company operates. For example, on a semi-annual basis, PCI releases platform upgrades that include market related enhancements and improvements that are suggested by PCI's network of clients. Moreover, the energy imbalance market releases enhancements which typically prompt changes to improve APS's dispatch model.[32]

Conclusion

We conclude that the PCI system provides APS with a reasonable optimization solution for its day-ahead and real-time traders for the correct dispatch of generating resources.

Off-System Sales

Off-system sales[33] refers to the sale of electric capacity and/or energy to wholesale or retail customers located outside of APS's service area. Off-system sales margin represents the difference between the energy revenue collected from off-system sales and the energy cost of providing such sales. Off-system sales are typically recorded in FERC account 447.

Larkin requested that APS provide listings of all of its off-system sales that were recorded in FERC account 447 for calendar years 2019, 2020 and for January 2021. In its response to Staff data request 1.52, the Company provided the relevant pages for Sales for Resale from its FERC Form filings for 2019 and 2020. For January 2021, the Company provided confidential attachment ExcelAPS21FA00085. APS's off-system sales for calendar year 2019 are summarized in the exhibit below:

Exhibit 4-4
Summary of APS's Off-System Sales for Calendar Year 2019

Description	Mega-Watt Hours Sold	Demand Charges	Energy Charges	Other Charges	Total
Subtotal - Required Service	256,008	$3,950,563	$ 9,497,558	$6,442,681	$ 19,890,802
Subtotal - Non-Required Service	3,829,007	$ -	$111,191,399	$ -	$111,191,399
Total Sales for Resale	4,085,015	3,950,563	120,688,957	6,442,681	131,082,201
Source: APS 2019 FERC Form 1 filing (provided in response to Staff Data Request 1.52)					

As shown in the above exhibit, for Required Service, the demand charges, energy charges and other charges totaled $3.951 million, $9.498 million and $6.443 million, respectively, for overall

[32] See the response to Staff data request 8.2, part e.
[33] Off-system sales are also referred to as Sales for Resale.

total Required Service of $19.891 million in 2019. For Non-Required Service, the energy charges totaled $111.191 million for overall off-system sales of $131.082 million in 2019.

APS's off-system sales for calendar year 2020 are summarized in the exhibit below:

Exhibit 4-5
Summary of APS's Off-System Sales for Calendar Year 2020

Description	Mega-Watt Hours Sold	Demand Charges	Energy Charges	Other Charges	Total
Subtotal - Required Service	96,199	$ 1,622,728	$ 3,356,818	$ 5,254,763	$ 10,234,309
Subtotal - Non-Required Service	2,992,109	$ -	$ 92,559,710	$ -	$ 92,559,710
Total Sales for Resale	3,088,308	1,622,728	95,916,528	5,254,763	102,794,019
Source: APS 2020 FERC Form 1 filing (provided in response to Staff Data Request 1.52)					

As shown in the above exhibit, for Required Service, the demand charges, energy charges and other charges totaled $1.623 million, $3.357 million and $5.255 million, respectively, for overall total Required Service of $10.234 million in 2020. For Non-Required Service, the energy charges totaled $92.560 million for overall off-system sales of $102.794 million in 2020.

Confidential attachment ExcelAPS21FA00085 from Staff data request 1.52 lists the Sales for Resale recorded in FERC account 447 for January 2021, which totaled $5.024 million.

The amounts indicated above for off-system sales in 2019, 2020 and January 2021 did not tie to the revenue from system excess sales in the Company's confidential PSA workpapers provided in Staff data request 1.95. We asked APS to reconcile the 2019, 2020 and January 2021 off-system sales amounts of $131.082 million, $102.794 million and $5.024 million, respectively, to the off-system sales included in the Company's monthly PSA filings. In its response to Staff data request 8.1, the Company stated the following:

> FERC Form 1 Sales for Resale includes all charges appropriately charged to FERC Account 447. However, the PSA POA only allows for "the revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power."
>
> Other power and gas system sales recorded in FERC Account 456 are included in the PSA monthly filings as Revenue from System Excess Sales and are not reported in FERC Form 1 Sales for Resale.

In addition to the explanation in the passage above, the Company provided the requested reconciliations of the off-system sales listed in the 2019 and 2020 FERC Form 1 filings and confidential attachment ExcelAPS21FA00085 (for January 2021) to the monthly amounts for Revenue from System Excess Sales from the confidential monthly PSA workpapers. The reconciliations are replicated in the exhibit below:

Exhibit 4-6
Reconciliation of Off-System Sales from PSA Workpapers to FERC Form 1 Filings

Reporting Period	PSA - System Excess Revenue Summary Page	Revenue - Sales for Resale FERC Form 1					PSA to FERC Form 1 Variance	Variance by FERC Account	
		447	447.3	447.4	447.6	Total FERC		447	456.11
Jan-2019	$ (4,581,028)	$ (507,264)	$ 881,697	$ (3,742,966)	$ (1,715,482)	$ (5,084,015)	$ 502,988	$ 507,264	$ (4,277)
Feb-2019	$ (17,038,296)	$ (889,528)	$ 1,280,006	$ (16,029,677)	$ (2,274,497)	$ (17,913,696)	$ 875,401	$ 889,528	$ (14,127)
Mar-2019	$ (13,709,195)	$ (1,089,634)	$ (3,524,731)	$ (8,874,464)	$ (1,190,389)	$ (14,679,218)	$ 970,024	$ 1,089,634	$ (119,610)
Apr-2019	$ (2,464,998)	$ (619,004)	$ 2,140,920	$ (4,113,547)	$ (517,924)	$ (3,109,554)	$ 644,557	$ 619,004	$ 25,553
May-2019	$ (898,913)	$ (763,151)	$ 4,597,567	$ (4,002,359)	$ (1,504,605)	$ (1,672,548)	$ 773,635	$ 763,151	$ 10,484
Jun-2019	$ (7,243,627)	$ (3,136,020)	$ 126,678	$ (5,218,824)	$ (2,071,193)	$ (10,299,358)	$ 3,055,732	$ 3,136,020	$ (80,289)
Jul-2019	$ (11,546,552)	$ (3,468,193)	$ (3,958,459)	$ (7,171,865)	$ (297,897)	$ (14,896,413)	$ 3,349,860	$ 3,468,193	$ (118,332)
Aug-2019	$ (10,821,936)	$ (3,456,993)	$ (2,941,928)	$ (7,437,324)	$ (424,535)	$ (14,260,782)	$ 3,438,846	$ 3,456,993	$ (18,147)
Sep-2019	$ (13,459,689)	$ (3,579,835)	$ (2,657,734)	$ (10,800,507)	$ (209,862)	$ (17,247,938)	$ 3,788,249	$ 3,579,835	$ 208,415
Oct-2019	$ (12,225,806)	$ (1,171,603)	$ (1,201,273)	$ (10,248,275)	$ (588,577)	$ (13,209,728)	$ 983,922	$ 1,171,603	$ (187,681)
Nov-2019	$ (5,970,039)	$ (363,192)	$ 145,745	$ (5,952,727)	$ (749,661)	$ (6,919,834)	$ 949,796	$ 363,192	$ 586,604
Dec-2019	$ (10,926,824)	$ (832,361)	$ (3,847,046)	$ (6,176,022)	$ (933,686)	$ (11,789,115)	$ 862,291	$ 832,361	$ 29,929
Total 2019	$ (110,886,902)	$ (19,876,778)	$ (8,958,558)	$ (89,768,557)	$ (12,478,309)	$ (131,082,201)	$ 20,195,298	$ 19,876,778	$ 318,523
Jan-2020	$ (3,176,997)	$ (474,258)	$ 815,912	$ (2,901,059)	$ (801,731)	$ (3,361,136)	$ 184,139	$ 474,258	$ (290,118)
Feb-2020	$ (4,630,442)	$ (841,587)	$ (645,819)	$ (3,470,694)	$ (618,326)	$ (5,576,426)	$ 945,984	$ 841,587	$ 104,397
Mar-2020	$ (4,157,329)	$ (721,003)	$ 496,336	$ (3,878,296)	$ (725,414)	$ (4,828,377)	$ 671,049	$ 721,003	$ (49,955)
Apr-2020	$ (4,916,746)	$ (506,993)	$ (448,331)	$ (3,664,873)	$ (600,645)	$ (5,220,842)	$ 304,096	$ 506,993	$ (202,897)
May-2020	$ (3,163,022)	$ (531,632)	$ (682,423)	$ (1,762,122)	$ (721,780)	$ (3,697,957)	$ 534,935	$ 531,632	$ 3,303
Jun-2020	$ (8,974,470)	$ (794,403)	$ (1,829,741)	$ (6,717,509)	$ (442,049)	$ (9,783,701)	$ 809,232	$ 794,403	$ 14,829
Jul-2020	$ (7,160,280)	$ (1,144,360)	$ (701,005)	$ (6,681,543)	$ (12,722)	$ (8,539,629)	$ 1,379,349	$ 1,144,360	$ 234,990
Aug-2020	$ (20,673,486)	$ (926,345)	$ (6,221,198)	$ (14,914,421)	$ (104,842)	$ (22,166,805)	$ 1,493,319	$ 926,345	$ 566,975
Sep-2020	$ (19,885,784)	$ (1,674,618)	$ 1,088,088	$ (20,315,463)	$ (303,953)	$ (21,205,947)	$ 1,320,163	$ 1,674,618	$ (354,455)
Oct-2020	$ (6,837,658)	$ (1,693,467)	$ (826,575)	$ (5,143,564)	$ (867,519)	$ (8,531,124)	$ 1,693,466	$ 1,693,467	$ -
Nov-2020	$ (6,066,730)	$ 197,821	$ (240,726)	$ (5,125,945)	$ (700,059)	$ (5,868,909)	$ (197,821)	$ (197,821)	$ -
Dec-2020	$ (3,169,607)	$ (843,559)	$ (226,678)	$ (1,629,372)	$ (1,313,557)	$ (4,013,166)	$ 843,559	$ 843,559	$ -
Total 2020	$ (92,812,551)	$ (9,954,403)	$ (9,422,160)	$ (76,204,859)	$ (7,212,597)	$ (102,794,019)	$ 9,981,469	$ 9,954,403	$ 27,068
Jan-2021	$ (4,107,006)	$ (916,717)	$ 215,242	$ (3,275,693)	$ (1,046,555)	$ (5,023,723)	$ 916,717	$ 916,717	$ -
Source: Staff Data Request 8.1, Attachment ExcelAPS21FA00324									

As shown in the above exhibit, the amounts shown under the column heading "PSA – System Excess Revenue Summary Page" are from the Company's confidential monthly PSA workpapers. No exceptions were noted. The columns listed by FERC account number are the monthly amounts embedded in the Company's FERC Form 1 filings. The amounts listed under the column heading "PSA to FERC Form 1 Variance" show the difference between what is reflected in the confidential PSA workpapers to the amounts shown under the "Total FERC" column (which tie back to APS's annual FERC Form 1 filings). The "Variance by FERC Account" column breaks out the PSA to FERC Form 1 Variance amounts between FERC Accounts 447 and 456.11.

We requested that APS identify the types of off-system sales (e.g., contractual off-system sales, short-term, day ahead, etc.) that are reflected in the PSA filings for each month of the 2019, 2020 and January 2021 review period. In its response to Staff data request 8.1, the Company provided Attachment ExcelAPS21FA00325, which broke out the types of off-system sales included in the monthly PSA filings and is replicated in the exhibit below:

Exhibit 4-7
Summary of the Types of Off-System Sales Reflected in the Monthly PSA Filings

Reporting Period	PSA - System Excess Revenue Summary Page	System Excess Revenue by Market						Other	
		Daily	Hourly	Intrahour	Long Term	Term	Total by Market	System Excess Rev	Total
Jan-2019	$ (4,581,028)	$ (2,707,736)	$ (189,245)	$ (688,868)	$ (178,594)	$ -	$ (3,764,442)	$ (816,585)	$ (4,581,028)
Feb-2019	$ (17,038,296)	$ (9,881,313)	$ (185,778)	$ (5,799,773)	$ (192,791)	$ -	$ (16,059,655)	$ (978,641)	$ (17,038,296)
Mar-2019	$ (13,709,195)	$ (4,688,349)	$ (121,454)	$ (7,424,656)	$ (174,761)	$ -	$ (12,409,220)	$ (1,299,975)	$ (13,709,195)
Apr-2019	$ (2,464,998)	$ (2,540,099)	$ (16,634)	$ 343,741	$ (170,416)	$ -	$ (2,383,408)	$ (81,590)	$ (2,464,998)
May-2019	$ (898,913)	$ (2,577,765)	$ (115,862)	$ 2,933,249	$ (130,710)	$ (395,200)	$ (286,289)	$ (612,624)	$ (898,913)
Jun-2019	$ (7,243,627)	$ (3,825,213)	$ (364,694)	$ (2,449,500)	$ (190,876)	$ -	$ (6,830,284)	$ (413,343)	$ (7,243,627)
Jul-2019	$ (11,546,552)	$ (5,002,962)	$ (70,809)	$ (5,032,196)	$ (267,228)	$ -	$ (10,373,195)	$ (1,173,358)	$ (11,546,552)
Aug-2019	$ (10,821,936)	$ (3,047,910)	$ (200,975)	$ (6,033,955)	$ (288,801)	$ -	$ (9,571,641)	$ (1,250,294)	$ (10,821,936)
Sep-2019	$ (13,459,689)	$ (6,336,717)	$ (127,968)	$ (5,781,038)	$ (256,570)	$ -	$ (12,502,293)	$ (957,396)	$ (13,459,689)
Oct-2019	$ (12,225,806)	$ (4,454,291)	$ (235,754)	$ (7,526,161)	$ (177,332)	$ -	$ (12,393,538)	$ 167,732	$ (12,225,806)
Nov-2019	$ (5,970,039)	$ (2,390,989)	$ (154,343)	$ (3,512,065)	$ (145,220)	$ -	$ (6,202,616)	$ 232,577	$ (5,970,039)
Dec-2019	$ (10,926,824)	$ (3,316,122)	$ (106,034)	$ (7,321,498)	$ (160,896)	$ (660,000)	$ (11,564,550)	$ 637,725	$ (10,926,824)
Total 2019	$ (110,886,902)	$ (50,769,465)	$ (1,889,552)	$ (48,292,720)	$ (2,334,194)	$ (1,055,200)	$ (104,341,131)	$ (6,545,771)	$(110,886,902)
Jan-2020	$ (3,176,997)	$ (2,571,675)	$ (18,723)	$ (623,569)	$ (80,171)	$ (495,464)	$ (3,789,601)	$ 612,604	$ (3,176,997)
Feb-2020	$ (4,630,442)	$ (1,514,136)	$ (57,377)	$ (3,070,445)	$ (112,399)	$ (414,231)	$ (5,168,587)	$ 538,145	$ (4,630,442)
Mar-2020	$ (4,157,329)	$ (2,333,107)	$ (77,815)	$ (1,469,750)	$ (121,483)	$ (34,945)	$ (4,037,100)	$ (120,228)	$ (4,157,329)
Apr-2020	$ (4,916,746)	$ (2,855,529)	$ (15,072)	$ (1,535,461)	$ (92,172)	$ (69,717)	$ (4,567,951)	$ (348,795)	$ (4,916,746)
May-2020	$ (3,163,022)	$ (708,505)	$ (91,709)	$ (2,104,680)	$ (119,017)	$ 82,373	$ (2,941,537)	$ (221,485)	$ (3,163,022)
Jun-2020	$ (8,974,470)	$ (3,588,457)	$ (98,709)	$ (4,419,296)	$ (102,697)	$ (715,240)	$ (8,924,399)	$ (50,070)	$ (8,974,470)
Jul-2020	$ (7,160,280)	$ (2,665,763)	$ (171,937)	$ (3,563,488)	$ 22,848	$ (739,040)	$ (7,117,380)	$ (42,900)	$ (7,160,280)
Aug-2020	$ (20,673,486)	$ (1,048,177)	$ (1,748,318)	$ (16,278,685)	$ -	$ (739,040)	$ (19,814,221)	$ (859,265)	$ (20,673,486)
Sep-2020	$ (19,885,784)	$ (9,358,080)	$ (1,666,094)	$ (3,536,713)	$ -	$ (2,495,200)	$ (17,056,088)	$ (2,829,696)	$ (19,885,784)
Oct-2020	$ (6,837,658)	$ (1,735,918)	$ (921,484)	$ (4,931,408)	$ -	$ 0	$ (7,588,810)	$ 751,151	$ (6,837,658)
Nov-2020	$ (6,066,730)	$ (618,778)	$ (409,404)	$ (2,504,497)	$ -	$ -	$ (3,532,679)	$ (2,534,051)	$ (6,066,730)
Dec-2020	$ (3,169,607)	$ (1,991,135)	$ (140,315)	$ (1,021,666)	$ -	$ -	$ (3,153,116)	$ (16,490)	$ (3,169,607)
Total 2020	$ (92,812,551)	$ (30,989,260)	$ (5,416,956)	$ (45,059,658)	$ (605,092)	$ (5,620,503)	$ (87,691,469)	$ (5,121,082)	$ (92,812,551)
Jan-2021	$ (4,107,006)	$ (1,914,453)	$ (180,511)	$ (1,465,092)	$ -	$ -	$ (3,560,056)	$ (546,950)	$ (4,107,006)

Source: Staff Data Request 8.1, Attachment ExcelAPS21FA00325

As shown in the above exhibit, the monthly amounts shown under the column heading "PSA – System Excess Revenue Summary Page" are from the Company's confidential monthly PSA workpapers. No exceptions were noted. The amounts shown in the additional columns breakout the system excess revenues by type, including: daily, hourly, intrahour, long-term, all of which total the system excess revenues by market. Combining the total system excess revenues by market with the other system excess revenues totals the amounts included in the confidential monthly PSA workpapers. No exceptions were noted.

We requested that APS identify by amount and account, the margins that were realized on the off-system sales that are reflected in the PSA filings for each month of the 2019, 2020 and January 2021 review period. In its response to Staff data request 8.1, the Company provided Attachment ExcelAPS21FA00326, which broke out the types of off-system sales included in the monthly PSA filings and is replicated in the exhibit below:

Exhibit 4-8
Summary of the Types of Off-System Sales Reflected in the Monthly PSA Filings

		Revenue			Expense				
Reporting Period	PSA System Excess Margin	447.4 (Sys Excess)	456 MTM and Gas Hedges	Total Revenue	547.2 Fuel	509 Carb Allow	565.6 Interco Trans	Total Expense	Margin
Jan-2019	$ 1,776,213	$ (3,742,966)	$ (4,277)	$ (3,747,242)	$ 1,779,892	$ 147,332	$ 43,804	$ 1,971,029	$ (1,776,213)
Feb-2019	$ 11,349,760	$ (16,029,677)	$ (14,127)	$ (16,043,804)	$ 4,205,095	$ 445,490	$ 43,459	$ 4,694,044	$ (11,349,760)
Mar-2019	$ 6,507,989	$ (8,874,464)	$ (119,610)	$ (8,994,073)	$ 2,079,031	$ 363,048	$ 44,006	$ 2,486,084	$ (6,507,989)
Apr-2019	$ 2,506,540	$ (4,113,547)	$ 25,553	$ (4,087,993)	$ 1,534,027	$ 5,136	$ 42,290	$ 1,581,453	$ (2,506,540)
May-2019	$ 486,496	$ (4,002,359)	$ 10,484	$ (3,991,874)	$ 3,275,648	$ 187,314	$ 42,416	$ 3,505,379	$ (486,496)
Jun-2019	$ 3,215,001	$ (5,218,824)	$ (80,289)	$ (5,299,112)	$ 1,813,222	$ 228,541	$ 42,348	$ 2,084,111	$ (3,215,001)
Jul-2019	$ 3,767,823	$ (7,171,865)	$ (118,332)	$ (7,290,197)	$ 3,110,165	$ 362,495	$ 49,715	$ 3,522,374	$ (3,767,823)
Aug-2019	$ 3,451,108	$ (7,437,324)	$ (18,147)	$ (7,455,472)	$ 3,560,360	$ 395,223	$ 48,781	$ 4,004,364	$ (3,451,108)
Sep-2019	$ 4,822,065	$ (10,800,507)	$ 208,415	$ (10,592,093)	$ 5,229,387	$ 493,476	$ 47,165	$ 5,770,028	$ (4,822,065)
Oct-2019	$ 5,565,825	$ (10,248,275)	$ (187,681)	$ (10,435,956)	$ 4,405,714	$ 420,272	$ 44,145	$ 4,870,131	$ (5,565,825)
Nov-2019	$ 2,688,603	$ (5,952,727)	$ 586,604	$ (5,366,123)	$ 2,397,081	$ 237,192	$ 43,248	$ 2,677,520	$ (2,688,603)
Dec-2019	$ 1,898,977	$ (6,176,022)	$ 29,929	$ (6,146,093)	$ 3,802,657	$ 401,757	$ 42,703	$ 4,247,116	$ (1,898,977)
Total 2019	$ 48,036,402	$ (89,768,557)	$ 318,523	$ (89,450,034)	$ 37,192,279	$ 3,687,274	$ 534,080	$ 41,413,633	$ (48,036,400)
Jan-2020	$ 679,955	$ (2,901,059)	$ (290,118)	$ (3,191,178)	$ 2,316,348	$ 150,525	$ 44,350	$ 2,511,223	$ (679,955)
Feb-2020	$ 1,523,368	$ (3,470,694)	$ 104,397	$ (3,366,297)	$ 1,623,035	$ 173,165	$ 46,730	$ 1,842,929	$ (1,523,368)
Mar-2020	$ 2,073,268	$ (3,878,296)	$ (49,955)	$ (3,928,251)	$ 1,668,985	$ 140,128	$ 45,870	$ 1,854,983	$ (2,073,268)
Apr-2020	$ 2,059,321	$ (3,664,873)	$ (202,897)	$ (3,867,770)	$ 1,731,054	$ 34,818	$ 42,577	$ 1,808,449	$ (2,059,321)
May-2020	$ 789,147	$ (1,762,122)	$ 3,303	$ (1,758,820)	$ 858,300	$ 65,568	$ 45,806	$ 969,673	$ (789,147)
Jun-2020	$ 3,295,961	$ (6,717,509)	$ 14,829	$ (6,702,680)	$ 3,344,773	$ 107,752	$ (45,806)	$ 3,406,719	$ (3,295,961)
Jul-2020	$ 2,157,103	$ (6,681,543)	$ 234,990	$ (6,446,553)	$ 3,269,465	$ 1,019,985	$ -	$ 4,289,450	$ (2,157,104)
Aug-2020	$ 8,684,840	$ (14,914,421)	$ 566,975	$ (14,347,446)	$ 5,085,294	$ 577,313	$ -	$ 5,662,606	$ (8,684,839)
Sep-2020	$ 14,763,322	$ (20,315,463)	$ (354,455)	$ (20,669,918)	$ 5,640,273	$ 266,323	$ -	$ 5,906,596	$ (14,763,321)
Oct-2020	$ 2,464,964	$ (5,143,564)	$ -	$ (5,143,564)	$ 2,299,071	$ 379,529	$ -	$ 2,678,600	$ (2,464,964)
Nov-2020	$ 3,792,152	$ (5,125,945)	$ -	$ (5,125,945)	$ 1,310,771	$ 23,022	$ -	$ 1,333,793	$ (3,792,152)
Dec-2020	$ 734,722	$ (1,629,372)	$ -	$ (1,629,372)	$ 646,795	$ 247,855	$ -	$ 894,650	$ (734,722)
Total 2020	$ 43,018,123	$ (76,204,859)	$ 27,068	$ (76,177,792)	$ 29,794,162	$ 3,185,982	$ 179,527	$ 33,159,670	$ (43,018,122)
Jan-2021	$ 1,230,831	$ (3,275,693)	$ -	$ (3,275,693)	$ 1,946,673	$ 98,189	$ -	$ 2,044,862	$ (1,230,831)

Source: Staff Data Request 8.1, Attachment ExcelAPS21FA00326

As shown in the above exhibit, the monthly amounts shown under the column heading "PSA System Excess Margin" are from the "Energy Transactions" tab in the Company's confidential monthly PSA workpapers. No exceptions were noted. The Revenue and Expense amounts are then broken out by FERC account, the totals of which net to the amounts shown under the "Margins" column. We tied these amounts back to the "Offsystem Margins" tab in the monthly confidential PSA workpapers. No exceptions were noted.

Using August 2020 as an example, the "Offsystem Margins" tab in the confidential monthly PSA workpapers breaks out the off-system sales volumes and margins by counterparty as shown in the exhibit below:

Exhibit 4-9
Other System Excess Sales Volumes and Margins by Counterparty for August 2020

Line No.	[redacted]	Volume (MWH)	Revenue ($)	Expense ($)	Margin ($)
1		400	$ 10,900	$ 5,192	$ 5,708
2		1,600	$ 53,088	$ 23,465	$ 29,623
3		2,525	$ 54,530	$ 46,872	$ 7,659
4	California Independent System Operator (EIM)	118,763	$ 9,137,880	$ 4,181,969	$ 4,955,911
5	[redacted]	17,882	$ 532,897	$ 379,780	$ 153,117
6		11,600	$ 330,744	$ 143,043	$ 187,701
7		5,600	$ 192,920	$ 62,036	$ 130,884
8		6,040	$ 155,436	$ 80,882	$ 74,555
9		210	$ 18,060	$ 4,562	$ 13,498
10		400	$ 8,516	$ 5,909	$ 2,607
11		800	$ 32,792	$ 9,731	$ 23,061
12		800	$ 27,600	$ 7,649	$ 19,951
13		175	$ 15,250	$ 5,319	$ 9,931
14		5,600	$ 178,240	$ 87,471	$ 90,769
15		870	$ 52,409	$ 15,586	$ 36,823
16		800	$ 26,632	$ 17,995	$ 8,637
17		800	$ 22,400	$ 11,590	$ 10,810
18		174,865	$ 10,850,294	$ 5,089,049	$ 5,761,245
19			$ 3,497,152	$ 573,557	$ 2,923,595
20		174,865	$ 14,347,446	$ 5,662,606	$ 8,684,840
Source: Confidential PSA Workpaper for August 2020 from Staff Data Request 1.95					

As shown in the above exhibit, the counterparty data is broken out by volume (MWh), revenue and expense from which the margin amounts are derived. With regard to line 4, the California Independent System Operator (EIM) represents transactions in the Energy Imbalance Market (see discussion below). In addition, line 19 – Other Items Accounted for as System Excess Sales, these amounts represent FAS 133, prior period true-ups, carbon obligation, and the margins from the settlement of financial instruments.[34] For each month of the 2019, 2020 and January 2021 review period, we tied the system excess revenue and system excess sales margins amounts to the Company's public monthly PSA filings. No exceptions were noted.

AG-X Customers

A portion of the Settlement Agreement from APS's rate case in Docket No. E-01345A-16-0036 related to the Company's AG-X customers. Among the provisions in the Settlement Agreement that was associated with AG-X customers relates to off-system sales in the PSA. Specifically, on page 22 of the Settlement Agreement from that proceeding it states:

> The PSA mitigation will remain in place. However, the mitigation is modified such that the resale of capacity and energy displaced by AG-X is established at a

[34] See Staff data request 1.95 on the Offsystem Margins tab.

flat $1,250,000 per month of off-system sales margins and excluded from the PSA rather than using a pro-rata share of such margins.

During the October 29, 2021 walkthrough of APS's PSA filings and confidential workpapers, the Company referenced this provision of the Settlement Agreement such that $15 million ($1,250,000 x 12) of off-system sales is being retained annually by APS pursuant to the AGX program. Upon reviewing the confidential PSA workpapers and public PSA filings, we verified that the Company has reflected the $1,250,000 in its PSA filings in each month of the review period. No exceptions were noted.

Energy Imbalance Market

The California Independent System Operator's EIM is a real-time energy market in the western United States. EIM's advanced market systems automatically find low-cost energy to serve real-time consumer demand across a wide geographic area. Pursuant to APS's participation in the EIM, we requested the Company's accounting treatment for imbalance market purchases, imbalance market sales and the recording of the related revenues. In its response to Staff data request 1.53, the Company provided a confidential attachment (APS21FA00140), which is a document titled "EIM Off System Sales Methodology" dated July 26, 2017 (and updated March 18, 2021). In the Background section of this document, it states:

> Off System (i.e., System Excess) sales are assigned generation cost on an hourly basis using the PCI Transaction Costing module which was implemented in 2016 in connection with the EIM/ETRM system changes. This methodology, as in the previous Transaction Evaluation (TranZEval) system, uses a stacking process to match APS's demand (load and sales), stacked from the bottom up based on transacting order, to APS's supply cost (purchases and generation), again stacked based on the cost to generate, lowest cost per MWh up to highest cost per MWh.
>
> This methodology results in the units with the lowest incremental cost assigned to load (the "transaction" at the bottom of the stack) with any subsequent Off System sales assigned their cost based on generation with increasingly higher incremental cost.

With regard to month-end reporting, the transaction costing methodology within the PCI Transaction Costing module is used to assign generation cost to EIM sales in a manner similar to other off-system sales. The specific assumptions and methodology in the Company's confidential document include the following:

- Off-system EIM sales or native load EIM purchases will be determined by the actual after-the-fact EIM Transfer Tags for energy transferred in or out of the APS Balancing Authority ("BA") from CAISO or other EIM participants. This will not necessarily equal the volumes associated with Instructed Imbalance Energy ("IIE") as not all transactions result in generation or leaving the BA. EIM Transfer Tags are also not generator specific and can be obtained from CAISO's Customer Market Results Interface ("CMRI").
- Settlement data for the following charge codes are used to determine prices for EIM transfers:

- 64600 – FMM[35] Instructed Imbalance Energy EIM Settlement
- 64700 – Real Time Instructed Imbalance Energy EIM Settlement
- 64750 – Real Time Uninstructed Imbalance Energy Settlement

- Revenue/MWh for hourly EIM sales will be determined by a weighted average for the hour for reimbursements related to 15 and 5-minute instructions to increase generation on (1) participating units to the extent of the settlement volumes for the hour, (2) non-participating units to the extent of the settlement volumes for the hour, and (3) uninstructed volumes for increases in participating and non-participating units. Cost/MWh for hourly EIM purchases will be determined by the weighted average cost for movements down for the hour in a similar manner.
- For each of the preceding categories, instructions up and instructions down for the hour are determined using settlement data at the 5-minute level for each generating unit. These net 5-minute values are aggregated to arrive at a total hourly instruction up and a total instruction down for each hour. The associated settlement amounts are summed for all units to determine the total settlement revenue or cost for the hour. A weighted average is then calculated to arrive at the revenue and cost per MW for each hour.
- Once the sale and purchase prices, based on CAISO settlements, has been determined for the EIM transfers, the PCI Transaction Costing process will assign fuel costs to the net sale for the hour or use the net purchase to serve load. Hourly off-system EIM sales will be served by the highest cost unit as the last sale made consistent with the treatment of term, day-ahead, and real-time sales. The methodology provided by PCI Transaction Costing assigns the lowest cost resources to load, assigning the higher cost generation to off-system sales.
- Remaining instructed and uninstructed EIM charges for instructions up and instructions down will be assigned to Account 447 as Native Load Balancing Activity Energy Revenue or Account 555 as Native Load Balancing Activity Energy Expense along with any settlements for Unaccounted for Energy ("UFE") under charge code 64740 – Real Time Unaccounted for Energy Settlement.

In addition, other EIM energy settlements included on the settlement statements for Ancillary Services, Bid Cost Recovery, and Imbalance Energy Offsets are aggregated on a daily basis, allocated based on net hourly EIM transfers, and assigned to Account 447 as Native Load Other Energy Revenue or Account 555 as Native Load Other Energy Expense. Moreover, EIM non-energy settlements for Grid Management charges, Over/Under Scheduling fees, etc. are also assigned to Account 555 as Native Load Purchased Power Expense.

APS's EIM market purchases for each month of 2019 and 2020 as well as January 2021 are summarized in the exhibit below:

[35] FMM = Fifteen-minute market.

Exhibit 4-10
Summary of Monthly EIM Purchases for the Period January 2019 – January 2021

Date	Purchase Quantity	Purchase Amount
Jan-2019	(47,380)	$ (1,385,696)
Feb-2019	(28,185)	$ (1,016,792)
Mar-2019	(41,634)	$ (1,144,151)
Apr-2019	(55,321)	$ (930,697)
May 2019	(61,833)	$ (403,412)
Jun-2019	(51,308)	$ (863,784)
Jul-2019	(49,329)	$ (1,048,863)
Aug-2019	(47,283)	$ (1,310,954)
Sep-2019	(43,403)	$ (670,385)
Oct-2019	(31,933)	$ (849,699)
Nov-2019	(60,005)	$ (1,065,186)
Dec-2019	(81,265)	$ (2,032,839)
Jan-2020	(70,374)	$ (1,228,484)
Feb-2020	(62,965)	$ (1,101,031)
Mar-2020	(38,662)	$ (495,265)
Apr-2020	(62,598)	$ (511,604)
May 2020	(105,570)	$ (1,345,638)
Jun-2020	(59,353)	$ (740,560)
Jul-2020	(62,604)	$ (1,286,967)
Aug-2020	(88,901)	$ (2,195,971)
Sep-2020	(48,817)	$ (754,781)
Oct-2020	(40,369)	$ (726,342)
Nov-2020	(76,725)	$ (1,655,048)
Dec-2020	(104,370)	$ (2,406,014)
Jan-2021	(50,263)	$ (994,657)
Source: Staff Data Request 1.53		

APS's EIM market sales for each month of 2019 and 2020 as well as January 2021 are summarized in the exhibit below:

Exhibit 4-11
Summary of Monthly EIM Sales for the Period January 2019 – January 2021

Date	Sales Quantity	Sales Amount
Jan-2019	51,268	$ 1,654,235
Feb-2019	111,260	$ 7,040,521
Mar-2019	81,107	$ 2,980,870
Apr-2019	55,133	$ 2,108,762
May 2019	100,579	$ 1,222,362
Jun-2019	140,156	$ 3,853,120
Jul-2019	150,078	$ 4,151,781
Aug-2019	170,809	$ 4,992,330
Sep-2019	172,381	$ 5,007,153
Oct-2019	260,074	$ 6,164,099
Nov-2019	97,640	$ 3,239,030
Dec-2019	113,139	$ 3,384,829
Jan-2020	89,256	$ 2,120,600
Feb-2020	66,144	$ 1,470,120
Mar-2020	72,971	$ 1,787,822
Apr-2020	80,463	$ 1,562,219
May 2020	60,953	$ 1,429,342
Jun-2020	103,620	$ 2,497,682
Jul-2020	105,068	$ 5,016,801
Aug-2020	118,763	$ 9,017,709
Sep-2020	121,793	$ 5,221,872
Oct-2020	117,220	$ 4,113,755
Nov-2020	66,694	$ 2,352,811
Dec-2020	33,361	$ 903,056
Jan-2021	72,513	$ 1,897,898
Source: Staff Data Request 1.53		

Larkin requested that the Company provide an evaluation of the cost savings resulting from EIM market purchases and the net margins realized on sales of energy into the imbalance market. In its response to Staff data request 1.53, for each month of 2019 and 2020 as well as January 2021, APS provided the EIM related cost savings for system excess sales that are summarized in the exhibit below:

Exhibit 4-12
Summary of Monthly EIM Cost Savings for the Period January 2019 – January 2021

System Excess Sales - EIM	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Revenue	$ 1,640,760	$ 7,394,030	$ 3,242,805	$ 2,263,786	$ 1,812,397	$ 3,605,732	$ 4,168,753	$ 4,989,874	$ 5,061,615	$ 6,007,482	$ 3,287,590	$ 3,460,669	$ 46,935,494
Fuel	$ (1,124,382)	$ (2,281,907)	$ (1,500,806)	$ (696,447)	$ (1,763,790)	$ (1,695,350)	$ (2,532,759)	$ (3,163,738)	$ (2,887,466)	$ (2,942,371)	$ (1,645,512)	$ (2,047,436)	$ (24,281,964)
Margin	$ 516,377	$ 5,112,123	$ 1,741,999	$ 1,567,339	$ 48,607	$ 1,910,382	$ 1,635,994	$ 1,826,136	$ 2,174,149	$ 3,065,111	$ 1,642,078	$ 1,413,233	$ 22,653,530
System Excess Sales - EIM	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Revenue	$ 1,375,639	$ 1,491,374	$ 1,859,440	$ 1,535,586	$ 1,394,699	$ 2,525,025	$ 3,002,600	$ 9,137,880	$ 5,046,914	$ 4,091,430	$ 2,328,579	$ 941,229	$ 34,730,395
Fuel	$ (1,214,904)	$ (851,530)	$ (862,534)	$ (797,546)	$ (792,071)	$ (1,313,758)	$ (1,641,542)	$ (4,181,969)	$ (2,237,027)	$ (1,767,133)	$ (1,418,740)	$ (663,659)	$ (17,742,412)
Margin	$ 160,735	$ 639,844	$ 996,906	$ 738,040	$ 602,628	$ 1,211,267	$ 1,361,058	$ 4,955,911	$ 2,809,887	$ 2,324,297	$ 909,839	$ 277,571	$ 16,987,982
System Excess Sales - EIM	January 2021												
Revenue	$ 1,673,159												
Fuel	$ (1,325,499)												
Margin	$ 347,660												
Source: Staff Data Request 1.53													

As shown in the exhibit above, the margins for EIM cost savings for system excess sales totaled $22.654 million for calendar 2019, $16.988 million for calendar 2020 and $347,660 for January 2021. According to the response to Staff data request 7.5, the EIM sales margins shown in the above exhibit were calculated based on sales of energy (i.e., netting energy revenue against allocated EIM transactions costs) and reflect the fuel and purchase power revenue and expense accounts that are authorized to be recovered through the PSA. We tied the amounts in the above exhibit to the confidential monthly PSA workpapers. No exceptions were noted.

With regard to EIM related cost savings, the Company also referred to the response to Staff data request 1.54, which requested the cost savings that have resulted from APS's participation in the EIM, and how the Company accounted for such savings. In its response to Staff data request 1.54, the Company stated that the EIM creates customer value through the economic dispatch of resources across the EIM western region in a manner that is more efficient than was the case prior to the implementation of the EIM. Specifically, value to the participants is created under the following two methods:

1. When the price of regional energy is above APS generation cost, units may be incrementally dispatched, and energy sold to other participants. These sales create positive margin to APS and reduce costs to customers overall.
2. When the price of energy within the EIM footprint is lower than APS's generation cost, APS units may be decremented. This allows APS to purchase energy from the market at a lower cost than generating. The reduction in costs associated with these incremental purchases is not something that is captured in accounting results, as those results capture actual burns and not reductions in forecasts.

With regard to the first methodology described above, APS referred to the margin accounting reflected in Exhibit 4-12.

According to the response to Staff data request 1.54, the CAISO produces a benefits summary for all EIM participants on a quarterly basis. These benefits are calculated using a counter-factual model that uses APS bid prices to model what systems operations costs would be without EIM as well as the savings created by EIM's economic dispatch. This includes not only margins created through energy sales, but also the reduction in cost created by lower-cost purchases. According to a CAISO Benefits Study conducted in the first quarter of 2021, APS gained the EIM-related benefits summarized in the exhibit below for the period 2016 through the first quarter of 2021.

Exhibit 4-13
Summary of APS EIM Benefits 2016 through 2021 (First Quarter)

APS EIM Benefits ($ Millions)						
2016	2017	2018	2019	2020	2021	Total
$ 5.98	$ 34.56	$ 45.30	$ 54.48	$ 48.96	$ 15.01	$ 204.29
Source: Staff Data Request 1.54						

As shown in the above exhibit, APS gained EIM benefits totaling $54.48 million in 2019, $48.96 million in 2020 and $15.01 million through the first quarter of 2021. In its response to Staff data request 7.5, the Company stated that the EIM benefits shown in the above exhibit represent both incremental off-system sales margins as well as reduced fuel costs due to the economic optimization across the EIM footprint. In addition, APS stated that these EIM benefits are calculated using an estimated benefits model in which historical APS bid prices are used to model what the system operation costs would have been (1) without the EIM, and (2) the savings created by the EIM's economic dispatch.

Energy Storage

Larkin requested that APS explain its use of energy storage in 2019, 2020 and in January 2021. In its response to Staff data request 1.59, the Company stated that it entered 2019 with three utility-scale storage projects in service in order to evaluate potential benefits to customers and to increase APS's understanding of how storage works with advanced technologies and the grid. The combined capacity of the three utility-scale projects is 6 MW/12 MWh. In addition, the Company evaluated intermediate and residential energy storage systems through small pilot programs.

One of the utility-scale projects is the McMicken energy storage battery facility, which experienced a catastrophic equipment failure in April 2019. As a result of this failure, out of caution, the Company took the other two utility-scale systems offline, both of which remained inactive until January 2021. The incident at the McMicken facility prompted the Company to initiate an internal investigation to determine the cause. In July 2020, the Company reported the findings of its investigation to the Commission and is currently applying what it learned from the investigation to integrate proper engineering as well as design and safety features towards future energy storage sites.

According to Staff data request 1.59, the Company currently plans to install a minimum of 850 MW of energy storage by 2025 in order to serve customer needs and to support its Clean Energy Commitment. The Company referred to the response to Staff data request 1.15 for information regarding Request for Proposals ("RFP") conducted during the review period in which APS sought energy storage resources. Upon our review, we noted that two such RFPs, both of which were announced in April 2019, were cancelled due to the incident that occurred at the McMicken battery storage facility. However, on December 11, 2020, the Company issued an RFP indicating a need for energy, procurement and construction services ("EPC") for approximately 60 MWAC[36], four-hour Battery Energy Storage System ("BESS") for APS to own and operate. This RFP was later revised on January 28, 2021 and was active as of June 18, 2021 (the date of the response to Staff data request 1.15). In addition, an approved Energy Storage System Power Purchase Tolling Agreement whereby APS contracted to purchase an energy storage system toll from El Sol Energy Storage LLC was executed on February 20, 2019.[37]

In the Company's PSA POA at section 9, subsection "a", which discusses allowable costs in the PSA, it states at page 10: "…and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts." We requested that APS identify, by FERC account and amount, the storage product costs recorded during 2019, 2020 and January 2021. In response to Staff data request 5.10, the Company stated that it did not incur battery storage costs or other electric storage costs during the 2019, 2020 and January 2021 review period. In addition, APS has not purchased nor installed utility-scale battery storage during the review period.[38]

[36] MWAC = Megawatt Alternating Current.
[37] A copy of this agreement was provided in response to Staff data request 1.3.
[38] See the response to Staff data request 8.3.

Review Related To Coal Order Processing

As it relates to APS's procedures for processing fuel purchase orders, the Company's coal orders are managed by APS's Coal Supply Agreements. With regard to the specific coal management procedures, in its response to Staff data request 1.16, the Company provided separate documents for the Cholla Plant and the Four Corners Plant, which are discussed in more detail below. With regard to the Navajo Generating Station, which closed in 2019, APS was not the operator of that power plant and thus did not provide detailed procedures related to processing fuel purchase orders at the Navajo Generating Station.[39]

The following is a description of APS's procedures for coal management procedures at the Cholla Plant:

Cholla Plant

As it relates to the processes for administering and managing the coal supply agreement for Cholla, the Company provided document referenced above is titled "Process: Cholla Fuels Contract Maintenance Process." The stated purpose of this document is as follows:

> The purpose of this document is to outline a process for planning, developing, and maintaining the Cholla fuel supply agreement. Discussed within are all major aspects of the fuel supply chain and major components of all associated contracts.

The Company departments to which these processes apply include the (1) Fuel Procurement Team, (2) Finance and Business Operations, (3) Generation Accounting, (4) Back Office Accounting, and (5) Resource Management Business Support. The personnel responsible for the processes for coal management procedures include the following positions and/or business areas:

1. Director of Fuel Procurement and Business Support – reviews and approves major contract milestones and changes.
2. Manager of Fuel Procurement – (1) reviews and approves major milestones and changes, and (2) provides contract guidance and direction.
3. Fuel Analyst/Consultant – (1) monitors and maintains fuel supply contracts, and (2) and is responsible for executing and communicating contract decisions within the parameters of approved contracts.
4. Fossil-Plant Operations - (1) communicates fuel supply chain concerns from a contractual and operational basis, and (2) provides contract support and input as needed to ensure that contract design meets the plant's needs.
5. Business Support – provides forecasts and studies to help guide contract changes and/or decisions.
6. Fossil FBO Analyst – (1) monitors and reports fuel forecasts and actuals, and (2) tracks fuel related expenses.
7. Back Office Accounting – (1) reviews fuel related invoices for accuracy and budget adherence, and (2) distributes fuel invoices for approval.

[39] See the response to Staff data request 1.60.

8. Generation Accounting – (1) reviews fuel related invoices against corporate budget and approves invoices for payment, and (2) invoices owners for their share of fuel related expenses.

The positions/business areas listed above are subject to the following accountability factors:

- Governance – The accountability to set the policies, rules, and broad boundaries that guide the development of methods, procedures, and practices to achieve the outcomes assigned to a function. Defines "what good is", what the rules are and broadly who is accountable for what.

- Oversight – The accountability to critically monitor work to ensure the desired functional outcomes are met.

- Support – the accountability to provide supplemental resources to performing organizations on an as-needed basis.

- Perform – The accountability to provide plans, schedules, scope, and detailed implementing procedures and to implement those plans to deliver the work products of the function.

The processes for the coal management procedures at Cholla is broken out by frequency of tasks common to maintaining Cholla's fuel supply, including: weekly tasks, monthly tasks, annual tasks, and as needed/seasonally. A separate process related to invoicing is handled separately. The exhibit below summarizes the correlation between the (1) positions/business areas, (2) accountability factors, and (3) frequency of tasks discussed above as it relates to processing coal management procedures at Cholla:

Exhibit 4-14
Summary of Processing Fuel Purchase Orders at Cholla Plant

Process Component	Director Fuel Procurement	Manager Fuel Procurement	Fuel Analyst/ Consultant	Fossil-Plant Operations	Business Support	Fossil FBO Analyst	Back Office Accounting	Generation Accounting
Weekly Tasks	Oversight	Governance	Perform	Perform	Support	Support	Support	Support
Monthly Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Annual Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
As Needed & Seasonal Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Invoicing	Oversight	Governance	Perform	Support	Support	Support	Perform	Perform

The tasks summarized in the above exhibit along with the invoicing process, are discussed on pages 4-10 of the Cholla Fuels Contract Maintenance Process document.

Four Corners Plant

As it relates to the processes for administering and managing the coal supply agreement for Four Corners, the Company provided the document referenced above titled "Procedure: Four Corners Contract Management." The stated purpose of this document is as follows:

> This document establishes a procedure for planning, developing, and maintaining the Four Corners coal supply agreement (CSA). Discussed within are all-major aspects of the fuel supply chain and major components of all associated contracts.

This procedure only applies to the Four Corners CSA between Arizona Public Service Company and Navajo Transitional Energy Company.

The personnel responsible for the processes for coal management procedures at Four Corners include the following positions and/or business areas:

1. Director - Fuel Procurement and Business Support – reviews and approves major contract milestones and changes.
2. Manager - Fuel Procurement – (1) reviews and approves major milestones and changes, and (2) provides contract guidance and direction.
3. Fuel Analyst/Consultant – (1) monitors and maintains fuel supply contracts, and (2) and is responsible for executing and communicating contract decisions within the bounds of approved contracts.
4. Fossil-Plant Operations - (1) communicates fuel supply chain concerns from a contractual and operational basis, and (2) provides fuel supply chain concerns from both a contractual and operational basis.
5. Business Support – provides forecasts and studies to help guide contract changes and/or decisions.
6. Fossil FBO Analyst – (1) monitors and reports fuel forecasts and actuals, and (2) tracks fuel related expenses.
7. Back Office Accounting – (1) reviews fuel related invoices for accuracy and budget adherence, and (2) distributes fuel invoices for approval.
8. Generation Accounting – (1) reviews fuel related invoices against corporate budget and approves invoices for payment, and (2) invoices owners for their share of fuel related expenses.

The positions/business areas listed above are subject to the following accountability factors: (1) Governance, (2) Oversight, (3) Support, and (4) Perform. These accountability factors are the same as those that apply to Cholla, which are discussed above.

Similar to Cholla, the processes for the coal management procedures at Four Corners is broken out by frequency of tasks common to maintaining Four Corner's fuel supply, including: daily tasks, weekly tasks, monthly tasks, quarterly tasks annual tasks, and as needed/seasonally. A separate process related to invoicing is handled separately. The exhibit below summarizes the correlation between the (1) positions/business areas, (2) accountability factors, and (3) frequency of tasks discussed above as it relates to processing coal management procedures at Four Corners:

Exhibit 4-15
Summary of Processing Fuel Purchase Orders at Four Corners Plant

Process Component	Director Fuel Procurement	Manager Fuel Procurement	Fuel Analyst/ Consultant	Fossil-Plant Operations	Business Support	Fossil FBO Analyst	Back Office Accounting	Generation Accounting
Daily Tasks	Oversight	Governance	Perform	Perform	Support	Support	Support	Support
Weekly Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Monthly Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Quarterly Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Annual Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
As Needed & Seasonal Tasks	Oversight	Governance	Perform	Support	Support	Support	Support	Support
Invoicing	Oversight	Governance	Perform	Support	Support	Support	Perform	Perform

The tasks summarized in the above exhibit along with the invoicing process, are discussed on pages 3-7 of the Four Corners Coal Contract Management document.

Invoices for Coal Purchases

In order to enable us to track the Company's processing of coal invoices, Larkin obtained copies of cash vouchers and payment documentation for fuel purchases recorded in August 2019, August 2020 and January 2021. These documents were provided in the confidential response to data request Staff data request 1.6. Specifically, for each month of 2019, 2020 as well as January 2021, the Company provided Cholla's coal purchase invoices that were issued by Peabody, Cholla's coal quality invoices also issued by Peabody and Four Corners coal purchase invoices that were issued by NTEC.

Larkin's review included tracing the invoices to the supporting data that was provided by the Company. Larkin first examined each invoice and compared the vendor name, invoice number and invoice date to the accompanying voucher and voucher supporting detail. The invoice detail broke out the purchases by ship date, description, outbound ID number, number of transport units, quantity, unit of measure, currency, price/UOM and amount. We then traced the total of the amount(s) listed for Cholla and Four Corners from the supporting detail to the invoices. No exceptions were noted.

Freight Vouchers

Staff data request 1.66 requested that APS provide freight cash vouchers for two days of coal receipts in August 2019, August 2020 and January 2021 as well as copies of the portions of the corresponding coal received reports. As it relates to Four Corners and the Navajo Generating Station, the Company stated that since both of those generating facilities are mine mouth power plants, there are no freight vouchers.

As it relates to Cholla, the response to Staff data request 1.66 included three confidential attachments, which contained the requested freight voucher documentation for August 2019, August 2020 and January 2021. Specifically, this documentation included:

- Copies of APS "Check Request" documents for each of the three periods noted. This document lists the invoice number, invoice date and description of the invoice detail (i.e., Cholla Freight).
- Copies of invoices for each of the Check Requests referenced above;

– Copies of freight bills issued by BNSF Railway Company, which totaled four freight bills for August 2019 and three freight bills for both August 2020 and January 2021.

Upon reviewing the aforementioned documents, Larkin verified the freight costs reflected on the BNSF freight bills tied to the corresponding invoices. In addition, Larkin tied out the amounts reflected on the invoices and freight bills to the APS check request documents. No exceptions were noted.

Fuel Analysis Reports

Staff data request 1.67 requested that APS provide the Company's procedures for preparing monthly fuel analysis reports. In response, the Company stated that for both Cholla and Four Corners, the sampling, analysis and fuel report preparation is provided by an independently-operated Coal Sampling and Analysis Provider ("CSASP"). Therefore, APS does not have a procedure for preparing monthly fuel analysis reports.[40] According to the response to Staff data request 2.2, and discussed in more detail later in this chapter, the CSASP for Cholla and Four Corners is SGS Mineral Services, (SGS North America Inc.).

As it relates to the Company's procedures for preparing monthly fuel cost and analysis reports, APS stated that its objectives for its monthly fuel analysis are to (1) identify factors that impact dispatch and generation decisions, and (2) to compare the result with the Company's pre-existing budget. Specific procedures include the following:[41]

- A Fuel Variance Report tracks the monthly variance between actuals and budget; it contains accounting data (from financial reporting and back- office accounting) and unit generation data from energy accounting. The detailed breakdown matches the Company's monthly Gross Margin Statement.
- A Fuel Variance Table is built based on hourly data through an analytical model to identify and calculate several factors that impact actual results as compared to budget. It provides more detailed dispatch analysis based on volume (load), price, outage/replacement power and other factors. It also shows how the Company utilizes resources during unit outage events.

The Company provided examples of these confidential reports in its response to Staff data request 1.40. Specifically, for the periods August 2019, August 2020 and January 2021, APS provided (1) a report titled APS Fuel & Purchased Power Summary Native Load and Excess Sales Fuel Cost Details, (2) a two-page report with Energy Variance Explanations (GWH) and Fuel Cost Variance Explanations, and (3) a report titled Fuel and Purchase Power Key Stories. A brief description of each report is below.

<u>APS Fuel & Purchased Power Summary Native Load and Excess Sales Fuel Cost Details</u>

This report reflects summarized monthly actual, budget and variance information for Fuel and Purchased Power Costs which are comprised of Total Dispatch Costs, Total Fixed Costs, Total

[40] As it relates to the Navajo Generating Station, which closed in 2019, APS was not the operator, therefore did not have procedures for preparing monthly fuel analysis reports.
[41] See the response to Staff data request 1.39.

Mark-to-Market ("MTM"), Total Off System Margin (excluding MTM and prior period adjustments) and Total Prior Period Adjustments.

The amounts summarized for Fuel and Purchase Power costs are broken out by the following: Generation Fuel (own load), Purchase Power (own load), Other (e.g., banked power), Off-System, and Native Load Hedger Liquidation. For the three periods for which these reports were provided, the total net system costs were overbudget by $22.070 million in August 2019, under budget by $16.871 million for August 2020 and under budget by $19.192 million for January 2021.

Energy Variance Explanations (GWH) and Fuel Cost Variance Explanations

This report reflects budget to actual information (and related variances) for both the Energy Variance Explanations (GWH) and Fuel Cost Variance Explanations on a native load basis, Off-System basis and a Total System basis for the following costs: Nuclear, Coal, Low Heat Rate Gas Units CC, High Heat Rate Gas Units, Term Purchases, Renewables, Daily/Hourly Purchases, Banking/Broker Fees, All Other, Gas Hedge Liquidation, Purchase & Power Hedge Liquidation and Power Financials/ISO Adjustment. In terms of the variance explanations, this report starts with the budgeted amount then breaks out the variances reasons as load, prices, outages, replacements, other to arrive at the actual monthly cost for each of the cost categories listed above.

Fuel and Purchase Power Key Stories

This report summarizes on a high level the monthly information for loads, commodity prices (gas and power), MTM, outages, off-system sales and average PSA cost. For example, the report for August 2019 indicates that overall sales were higher than budget due to higher summer demand. In terms of commodity prices, the August 2019 report reflected the following:

Commodity	Max	Min	Average	Budget Variance
Gas	$ 3.91	$ 1.74	$ 2.27	$ 0.13
Power	$ 72.32	$ 24.80	$ 39.46	$ (13.42)

- Average gas prices were higher than budget due to the price spike in the last week of the month driven by weather and demand.
- Electricity prices were lower than budget for majority of time of the month with a small spike in the 4th-5th due to demand.

Mark-to-Market - $2.7 million value change in the MTM contract result from the lower forward curve in gas prices.

Outages –

- No planned outages in baseload units.
- Short period of unplanned outage for West Phoenix CCC5, Palo Verde 2 and Four Corners, but the rest of the fleet had great performance through the month with a net saving if $1.9M) in outage-replacement activities.

Off-System – The off-system sales had a margin credit ($3.5 million)- which was $8.3 million lower than budget due to lower budget sales.

Average PSA Cost –

- Average cost of \$3.58 ¢/kWh; 0.40¢ higher than budget.
- The higher than budget fuel costs led to higher PSA balance of \$51.8 million under collected.

Retroactive Escalations

Larkin requested that APS identify all pending or approved retroactive escalations that affected fuel cost for the 2019, 2020 and January 2021 review period. In its response to Staff data request 1.69, the Company stated that there are no pending or approved retroactive escalations affecting fuel costs during the review period.

Review Related To Station Visitation And Coal Processing Procedures

Larkin conducted on-site plant visits to the Company's Cholla Power Plant on August 24, 2021 and the Four Corners Plant on August 25, 2021. As discussed previously in Chapter 3, as it relates to Cholla, APS owns and operates Units 1 and 3, which have capacity of 116 MW and 271 MW, respectively. As it relates to Four Corners, APS has a 63 percent ownership stake and operates Units 4 and 5, each of which have capacity of 485 MW.

Pursuant to these on-site visits, we observed the following at both power plants:

- Plant operations
- Coal inventory at the plants
- Ash pond remediation to date
- Interviewed plant personnel including the plant manager at both plants
- At Four Corners, Larkin and EVA were allowed into the NTEC area to observe the testing lab and riding the train from the mine to the plant unloading area.

During our on-site plant visits to both Cholla and Four Corners, we requested that a Company employee take photographs of various sites at both locations. The Company provided copies of the requested photographs in its confidential response to Staff data request 3.3 and are included in Appendix A for the Cholla plant and Appendix B for the Four Corners plant.

Coal Receiving

A description of the Company's coal receiving procedures and controls for shortages, overages, and other discrepancies for the Cholla and Four Corners coal plants was provided in APS's responses to Staff data request 1.71 and Staff data request 1.72. The process for how coal is weighed as received at each plant is as follows:

Cholla Plant

Pursuant to its contract with Peabody CoalSales, LLC ("Peabody CoalSales"), APS purchases coal at the mine from Peabody. The coal is weighed at the mine and APS and BNSF rail accept the mine's certified scales for weighing the coal. The mine scales, which are sealed, are certified in the spring and fall annually by the New Mexico Department of Agriculture. In the event the seals on the mine scales are broken, a re-certification test is conducted. APS may attend the bi-annual scale testing and has done so in the past. Belt scales at Cholla (which are actually meters and not scales) are used to meter the coal tonnage from unloading to either the units or the reclaim pile. The coal belt meters are used to measure the coal obtained from each railcar for comparison to the railroad and/or mine manifest. The coal belt meters trigger belt scale preventative maintenance in instances where a 3 percent deviation exists between the mine manifest weight and the Cholla belt meter reads. In terms of shortages, overages or other discrepancies, the Company stated that since the coal is weighed at the mine, any discrepancies are typographical or clerical in nature. As it relates to discrepancies involving freight bills or railcar numbers, any such discrepancies between APS and BNSF are reconciled against the shipping manifests that use the scales at the mine. According to the response to Staff data request 1.73, in the event an error is detected that results in a change in dollar amount, a new invoice is issued.

Four Corners Plant

The coal is stock-piled adjacent to the generating unit by the supplier (the mine) and is delivered to the coal silos via conveyor belt hourly as needed for operations. The coal is sampled for analysis (see discussion below) and weighed by calibrated coal scales while in route on the conveyor belts between the mine and the plant. Ownership of the coal transfers from NTEC to APS at the scales and both are subject to the results of this scale and coal analysis. In terms of shortages, overages and other discrepancies, there are no procedures or controls in place since the scales are the singular point of measurement for both Four Corners and NTEC. For the same reason, there are no freight bill or car number discrepancies at Four Corners.[42]

Navajo Generating Station

The SRP was the operator of the Navajo Generating Station (which closed in 2019), and therefore maintained its own separate coal receiving and discrepancy procedures.

Coal Sampling

Larkin also reviewed the Company's procedures for coal sampling, including (1) the frequency of coal sampling, (2) how the coal samples are identified, and (3) what control is exercised over forwarding coal samples to the laboratory, which was provided in the response to Staff data request 1.76 and summarized below:

<u>Cholla Power Plant</u>

> The sampling and analysis is performed by an independently-operated Coal Sampling and Analysis Provider ("CSASP"). A sample is taken from each train as it is loaded at the mine and follows American Society for Testing and Materials ("ASTM") D 7430 Mechanical Sampling of Coal. Each sample is identified by a unique sample number. Approximately 60 lbs is sampled for same-day quick testing and the final testing results for invoicing are sent two to three days later.

[42] See the response to Staff data request 1.73.

Four Corners Plant

> The sampling and analysis is performed by an independently operated CSASP. The coal supplier and the plant jointly own the on-site laboratory from which the CSASP operates. The coal sampling system consists of two coal belt mechanical samplers, which follow ASTM D 7430 Mechanical Sampling of Coal. The number of samples is determined by the weight of the coal delivered through the sampling system for each calendar day divided by 2,000 (the maximum tonnage represented by a single sample). All analyses for purposes of coal billing are completed on-site.

As previously discussed, the response to Staff data request 2.2 stated that the independently operated CSASP is SGS Mineral Services, (SGS North America Inc.). With regard to Cholla, there is no direct contract between APS and SGS North America Inc. Rather, the coal sampling and analysis is included in Article 7 of the base coal supply agreement with Peabody CoalSales. With regard to Four Corners, there is a contract between SGS North America Inc. and Bisti Fuels, which is a direct contractor of NTEC. Although APS is a partial owner of Four Corners, is not a party to SGS North America Inc. contract. APS (and the other owners of Four Corners) reimburse Bisti Fuels for 50 percent of incurred laboratory costs.[43]

Navajo Generating Station

With regard to the Navajo Generating Station, SRP was the operator and therefore maintained its own separate coal sampling procedures.

Staff data request 1.74 requested a description of how damaged railcars are checked and who instigates claims for shortages. In response, APS stated that as it relates to Cholla, railcar counts are compared to the shipping manifests. The railcars are leased from BNSF, therefore, any damaged or missing railcars are the responsibility of the supplier. With regard to Four Corners, as previously noted, this facility is a mine mouth power plant whereby coal is stockpiled by NTEC on their property and delivered via conveyor belts on an hourly basis as needed. Therefore, there are no railcars to checked nor is there the possibility of claims for shortages. With regard to the Navajo Generating Station, the Company stated that SRP was the operator of that facility and therefore maintains the description of how damaged railcars were checked and who instigated claims for shortages.

Monthly Cut-Off Procedures

With regard to the Company's monthly cut-off procedures for coal, for Cholla, the month-end inventory amounts are calculated by (1) taking the starting inventory, (2) subtracting plant coal burn, and (3) adding any coal in-transit, waiting to be unloaded, or unloaded during the month. For Four Corners, scale quantities are read each day at 00:00 (i.e., midnight) in order to record the amount of sold tons in the calendar day. These daily readings are then dispersed between the Company, the coal supplier and the independently-operated laboratory. SRP was the operator of the Navajo Generating Station and maintained any coal-related month-end cut-off procedures.

[43] See the response to Staff data request 2.2.

Scale Calibration

Scale calibration logs for each month of 2019, 2020 and January 2021 were requested in Staff data request 1.77. In its response, the Company stated that for Cholla, the coal supplier calibrates the scales twice annually. For 2019, APS provided calibration logs dated April 9, 2019, and October 9, 2019. For 2020 however, due to Covid-19 restrictions, only one scale calibration occurred, which was November 10, 2020. For Four Corners, the coal supplier calibrated the scales twice during the review period, including on May 1, 2019, and on September 17, 2020. However, the Company was unable to provide the scale calibration results from May 1, 2019. For the Navajo Generating Station, since SRP was the operator, APS does not have scale calibration logs for that facility.

We reviewed the scale calibration logs that were provided for Cholla and Four Corners, and noted that there were generally no problems noted on the scale calibration logs.

A description of the procedures followed when coal scales are inoperable was provided in the response to Staff data request 1.78 including:

- Cholla: No trains are loaded at the mine (the point of sale) when the scales are inoperable. At the plant, there are redundant belt meters along each path from the pile or train on the way to the coal silos. There is no path the coal can take where coal is measured multiple times while in route to the coal silos.
- Four Corners: The coal supplier maintains two sets of coal scales at the point of sale, which is one scale on each of two coal conveyor belts. If one conveyor belt or coal scale becomes inoperable, the coal supply is switched to the other conveyor belt and scale. If coal supply cannot pass through the point of sale, then coal must be supplied to the emergency coal conveyor belt. In this event, NTEC must truck the coal and no scale is used. Upon the emergency being completed, NTEC uses professional survey equipment and engineering software to calculate the tons of coal supplied.
- Navajo: SRP followed its own procedures when coal scales were inoperable at the Navajo Generating Station.

Lab Sampling Reports

Copies of laboratory sampling reports for coal purchases recorded in August 2019, August 2020 and January 2021 were requested in Staff data request 1.79 in order to compare such reports with accounting and purchasing records. The Company's response to Staff data request 1.79 included the requested laboratory sampling reports for Four Corners whereas the requested sampling information for Cholla was included in the quality analysis information provided in the response to Staff data request 1.6. APS stated that as operator of the Navajo Generating Station, SRP maintained copies of the lab sampling reports for that facility.

Coal Handling from Stockpile to Firebox

APS's procedures for handling coal from the stockpile to the firebox or boiler at the Cholla Plant and Four Corners Plant were provided in response to Staff data request 1.80. Specifically, for Cholla, coal is loaded from the reclaim pile onto a conveyor belt into coal silos. In addition, coal can be directly unloaded from railcars into the conveyor belt system. As it relates to Four Corners, this plant does not maintain coal stockpiles. Rather, coal is stockpiled adjacent to the

Four Corners facility by NTEC on its property and delivered to the coal silos on conveyor belts hourly as needed. SRP maintained the requested procedure for the Navajo Generating Station.

<u>Physical Inventory</u>

APS's procedures for taking physical inventories of coal and fuel oil are described in the response to Staff data request 1.81. With regard to Four Corners, the Company does not maintain any coal stockpiles or fuel oil. As noted above, coal is stockpiled adjacent to Four Corners by NTEC. Therefore, Four Corners does not have procedures for taking physical inventories. With regard to Cholla, the Company provided the following explanation:

> Each spring and fall, a coal pile survey (using GPS drive-over) is conducted (by a third party) at Cholla to measure the size of the coal pile. Each fall, a drilled core sample test of the coal pile is taken to analyze the density of the coal pile. If the GPS survey results show a deviation of < > 5% from the Cholla coal pile inventory volume, an adjustment is made to the APS coal pile book inventory. The last adjustment was made in 2012. The lack of a need to make inventory adjustments supports that the calculations for inventory and fuel burns are reasonably accurate. Fuel oil at Cholla is stored on site in tanks with sight glasses and electronic measurement for inventory levels.

The Company provided the results of coal stockpile surveys conducted in 2019 and 2020 at the Cholla plant. Specifically, the Company conducted two coal stockpile surveys in 2019 (i.e., June 17 and November 12) and two coal stockpile surveys in 2020 (i.e., June 1 and November 13). The results of the coal stockpile survey conducted on June 17, 2019, is summarized in the exhibit below:

Exhibit 4-16
Comparison of Cholla Inventory Tons vs. Coal Stockpile Survey Results at June 17, 2019

	El Segundo / Lee Ranch (Alt 1A Pile)	(5) Spring Creek (Alt 3 Pile)	Total Coal Inventory
Cholla Book Inventory - June 17, 2019	454,079	101,806	555,885
+/- Adjustments	-	-	-
Adjusted Book Inventory	454,079	101,806	555,885
Coalpile Tons - Mikon (GPS Survey)	466,295	93,654	559,949
- less Capitalized Base Coalpile	-	-	-
Adjusted Mikon Survey Quantity	466,295	93,654	559,949
Variance (Tons)	(12,216)	8,152	(4,064)
Variance (%) - June 17, 2019	-2.690%	8.007%	-0.731%

Source: Staff Data Request 1.83

As shown in the exhibit above, the Company's total adjusted book inventory was 555,885 tons whereas the GPS survey results indicated total coal inventory of 559,949 tons, or a variance of (4,064) tons and a percentage difference of -0.731 percent, which is within the < > 5 percent threshold described in the passage above from the response to Staff data request 1.81. Based on those guidelines, no inventory adjustment was made.

The results of the coal stockpile survey conducted on November 12, 2019, is summarized in the exhibit below:

Exhibit 4-17
Comparison of Cholla Inventory Tons vs. Coal Stockpile Survey Results at November 12, 2019

	El Segundo / Lee Ranch (Alt 1A Pile)	(5) Spring Creek (Alt 3 Pile)	Total Coal Inventory
Cholla Book Inventory - November 12, 2019	391,015	56,574	447,588
+/- Adjustments	-	-	-
Adjusted Cholla Book Inventory	391,015	56,574	447,588
Coalpile Tons - Mikon (GPS Survey)	408,879	49,644	458,523
- less Capitalized Base Coalpile	-	-	-
Adjusted Mikon Survey Quantity	408,879	49,644	458,523
Variance (Tons)	(17,864)	6,930	(10,935)
Variance (%)	-4.569%	12.249%	-2.443%

Source: Staff Data Request 1.83

As shown in the exhibit above, the Company's total adjusted book inventory was 447,588 tons whereas the GPS survey results indicated total coal inventory of 458,523 tons, or a variance of (10,935) tons and a percentage difference of -2.443 percent, which is within the <>5 percent threshold described in the passage above from the response to Staff data request 1.81. Based on those guidelines, no inventory adjustment was made.

The results of the coal stockpile survey conducted on June 1, 2020, is summarized in the exhibit below:

Exhibit 4-18
Comparison of Cholla Inventory Tons vs. Coal Stockpile Survey Results at June 1, 2020

	El Segundo / Lee Ranch (Alt 1A Pile)	(5) Spring Creek (Alt 3 Pile)	Total Coal Inventory
Cholla Book Inventory - June 1, 2020	582,817	32,176	614,993
+/- Adjustments	-	-	-
Adjusted Cholla Book Inventory	582,817	32,176	614,993
Coalpile Tons - Mikon (GPS Survey)	593,629	23,198	616,827
- less Capitalized Base Coalpile	-	-	-
Adjusted Mikon Survey Quantity	593,629	23,198	616,827
Variance (Tons)	(10,812)	8,978	(1,834)
Variance (%)	-1.855%	27.902%	-0.298%

Source: Staff Data Request 1.83

As shown in the exhibit above, the Company's total adjusted book inventory was 614,993 tons whereas the GPS survey results indicated total coal inventory of 616,827 tons, or a variance of (1,834) tons and a percentage difference of -0.298 percent, which is within the <>5 percent threshold described in the passage above from the response to Staff data request 1.81. Based on those guidelines, no inventory adjustment was made.

The results of the coal stockpile survey conducted on November 13, 2020, is summarized in the exhibit below:

Exhibit 4-19
Comparison of Cholla Inventory Tons vs. Coal Stockpile Survey Results at November 13, 2020

	El Segundo / Lee Ranch (Alt 1A Pile)	(5) Spring Creek (Alt 3 Pile)	Total Coal Inventory
Cholla Book Inventory - November 13, 2020	182,674	-	182,674
+/- Adjustments	-	-	-
Adjusted Cholla Book Inventory	182,674	-	182,674
Coalpile Tons - Mikon (GPS Survey)	178,414	-	178,414
- less Capitalized Base Coalpile	-	-	-
Adjusted Mikon Survey Quantity	178,414	-	178,414
Variance (Tons)	4,260	-	4,260
Variance (%)	2.332%	0.000%	2.332%

Source: Staff Data Request 1.83

As shown in the exhibit above, the Company's total adjusted book inventory was 182,674 tons whereas the GPS survey results indicated total coal inventory of 178,414 tons, or a variance of 4,260 tons and a percentage difference of 2.332 percent, which is within the <>5 percent threshold described in the passage above from the response to Staff data request 1.81. Based on those guidelines, no inventory adjustment was made.

As the operator of the Navajo Generating Station (prior to closing in 2019), SRP maintained the procedure for taking physical inventories of coal and fuel oil at that facility.

Generating Station Reports

Larkin requested copies of generating station reports for the review period in Staff data request 1.85. In response to our request, APS referred to the monthly fuel reports for Cholla on coal processing procedures, inventories and results (discussed above). In addition, in its response to Staff data request 1.85, APS provided reports for the disposition of fly ash at Four Corners, including bottom ash shipments and cenosphere shipments in 2019, 2020 and January 2021. We reviewed these reports, which were provided by Salt River Materials Group and which listed the bottom ash and cenosphere shipments for each month of the review period. The bulk of the activity in these reports related to the monthly disposition of fly ash as there was minimal activity related to monthly cenosphere shipments during the review period, including a total of 39.24 tons in 2019, 23.63 tons in 2020 and zero tons in January 2021.

Staff data request 1.86 asked the Companies to identify any internal investigations which resulted from what was reported on the generating station reports provided in Staff data request 1.85 for the review period. APS responded that internal investigations are completed using either an Event Free Clock Reset or a Critical Learning Event ("CLE") and that corrective actions are determined based on the events that occurred. In addition, APS stated that one CLE for fly ash was completed during the review period. Specifically, this event occurred on October 8, 2019, and identified by FC-2019-00254. The details of this event are as follows:

> Close Call – [redacted] mechanical labor preparing to open the 5 west fly-ash surge silo access door. While [redacted] was preparing to begin work, an Auxiliary Operator questioned their work-scope. [redacted] indicated that they were tasked to gain access to the 5W surge silo vessel, in preparation for an outage inspection. The operator informed the contracting group that the surge silo did not have proper isolation for their scope of work.

Larkin requested copies of the station reports for the review period which were sent to the Company's general office for incorporation into company statistics and to provide workpapers sufficient to trace the reports to those statistics in Staff data request 1.87. In response, APS stated that it currently utilizes the GADS software program through PowerSuite to maintain generation statistics whereby plant data is fed through the program and a validation completed each month to check for errors. With regard to station reports, in its supplemental response to Staff data request 1.87, APS stated:

> No formal reports are provided to the Company's general offices regarding operating statistics at generating units. All information is entered into the GADS software program discussed above. Output from this software is then used to develop reports for management review, including generation and other relevant information in the monthly PSA reports provided in response to Staff 1.94.

The Company's PSA filings and confidential workpapers are discussed in detail in a later section of this chapter.

Review Related To Fuel Costs

Pursuant to the PSA POA, fuel expense is among the includable costs in the PSA with such costs being recorded in the following FERC Accounts: (1) 501 – Fuel (Steam), (2) 518 – Fuel (Nuclear) less ISFSI regulatory amortization, and (3) 547 – Fuel (Other Production). In the Company's confidential monthly PSA workpapers, APS breaks out fuel expense by (1) gas generation, (2) gas generation under tolling agreements, (3) gas hedges and mark-to-market expense, (4) oil generation, (5) coal generation, and (6) nuclear generation.

Coal generation comprised the bulk of APS's fuel expense during the review period. The coal costs for the Cholla, Four Corners and Navajo generating plants for each month of the review period are summarized in the exhibit below:

Exhibit 4-20
Summary of Monthly Coal Costs at the Cholla, Four Corners and Navajo generation plants during the period January 2019 through January 2021

Coal Fueled Generating Unit	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Cholla Unit 1	$ 658,972	$ 166,821	$ 182,105	$ 192,738	$ 369,064	$ 929,873	$ 1,272,172	$ 1,297,634	$ 1,061,187	$ 1,036,510	$ 1,330,360	$ 1,298,212	$ 9,795,648
Cholla Unit 3	$ 1,641,941	$ 2,344,360	$ 3,018,347	$ 3,116,233	$ 1,753,256	$ 2,261,762	$ 3,557,022	$ 3,427,229	$ 2,292,159	$ 1,685,367	$ 3,466,842	$ 3,479,055	$ 32,043,572
Total Cholla Coal Costs	$ 2,300,913	$ 2,511,180	$ 3,200,452	$ 3,308,971	$ 2,122,320	$ 3,191,635	$ 4,829,195	$ 4,724,863	$ 3,353,346	$ 2,721,876	$ 4,797,202	$ 4,777,267	$ 41,839,220
Four Corners Unit 4	$ 8,395,463	$ 8,242,364	$ 2,933,179	$ 5,669,078	$ 6,697,818	$ 7,673,750	$ 9,359,163	$ 9,469,432	$ 8,181,025	$ 8,784,111	$ 8,152,930	$ 10,206,673	$ 93,764,987
Four Corners Unit 5	$ 7,254,893	$ 7,260,401	$ 2,743,962	$ 7,860,379	$ 4,134,708	$ 7,883,963	$ 8,833,661	$ 8,986,582	$ 7,552,546	$ 4,176,302	$ 5,561,127	$ 7,103,444	$ 79,351,967
Total Four Corners Coal Costs	$ 15,650,356	$ 15,502,765	$ 5,677,141	$ 13,529,458	$ 10,832,526	$ 15,557,712	$ 18,192,824	$ 18,456,014	$ 15,733,571	$ 12,960,413	$ 13,714,057	$ 17,310,118	$ 173,116,954
Navajo Unit 1	$ 978,533	$ 993,319	$ 830,403	$ 1,273,935	$ 1,114,189	$ 882,405	$ 1,264,793	$ 2,218,387	$ 1,543,520	$ 1,333,012	$ 149,093	$ 125,458	$ 12,707,049
Navajo Unit 2	$ 997,070	$ 1,012,136	$ 846,134	$ 1,298,068	$ 1,135,296	$ 899,121	$ 1,288,753	$ 2,260,411	$ 1,572,760	$ 1,358,264	$ 151,917	$ 127,835	$ 12,947,766
Navajo Unit 3	$ 975,399	$ 990,138	$ 827,744	$ 1,269,856	$ 1,110,621	$ 879,580	$ 1,260,743	$ 2,211,283	$ 1,538,577	$ 1,328,743	$ 148,616	$ 125,057	$ 12,666,356
Total Navajo Coal Costs	$ 2,951,002	$ 2,995,592	$ 2,504,281	$ 3,841,859	$ 3,360,107	$ 2,661,106	$ 3,814,288	$ 6,690,081	$ 4,654,858	$ 4,020,020	$ 449,626	$ 378,350	$ 38,321,171
Total 2019 Coal Expense	$ 20,902,271	$ 21,009,537	$ 11,381,875	$ 20,680,287	$ 16,314,953	$ 21,410,454	$ 26,836,306	$ 29,870,958	$ 23,741,775	$ 19,702,309	$ 18,960,884	$ 22,465,735	$ 253,277,345

Coal Fueled Generating Unit	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Cholla Unit 1	$ 1,181,464	$ 472,561	$ 1,156,061	$ 535,475	$ 1,112,518	$ 1,407,209	$ 1,422,324	$ 1,668,967	$ 1,351,129	$ 1,074,937	$ 802,945	$ 462,884	$ 12,648,473
Cholla Unit 3	$ 2,945,402	$ 1,828,571	$ 2,786,446	$ 2,249,228	$ 2,714,564	$ 3,208,516	$ 3,623,693	$ 4,049,416	$ 3,295,974	$ 3,350,092	$ 2,094,156	$ 1,218,902	$ 33,364,960
Total Cholla Coal Costs	$ 4,126,867	$ 2,301,132	$ 3,942,507	$ 2,784,703	$ 3,827,082	$ 4,615,725	$ 5,046,016	$ 5,718,383	$ 4,647,103	$ 4,425,029	$ 2,897,101	$ 1,681,786	$ 46,013,433
Four Corners Unit 4	$ 6,864,382	$ 8,350,648	$ 8,367,341	$ 7,821,875	$ 2,437,384	$ 3,410,808	$ 8,527,210	$ 9,677,458	$ 8,914,450	$ 6,543,290	$ 2,287,203	$ 6,606,016	$ 79,808,065
Four Corners Unit 5	$ 10,445,680	$ 4,793,022	$ (222,607)	$ (473,174)	$ 5,798,871	$ 8,267,410	$ 10,826,392	$ 6,839,644	$ 9,152,958	$ 3,883,932	$ 4,460,257	$ 7,664,408	$ 71,436,793
Total Four Corners Coal Costs	$ 17,310,062	$ 13,143,670	$ 8,144,734	$ 7,348,701	$ 8,236,255	$ 11,678,217	$ 19,353,601	$ 16,517,102	$ 18,067,409	$ 10,427,222	$ 6,747,460	$ 14,270,423	$ 151,244,858
Navajo Unit 1	$ 75,123	$ (77,481)	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 29,512	$ 292,761
Navajo Unit 2	$ 76,546	$ (78,948)	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 30,071	$ 298,307
Navajo Unit 3	$ 74,882	$ (77,233)	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 29,417	$ 291,823
Total Navajo Coal Costs	$ 226,552	$ (233,662)	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 89,000	$ 882,890
Total 2020 Coal Expense	$ 21,663,480	$ 15,211,141	$ 12,176,241	$ 10,222,404	$ 12,152,337	$ 16,382,942	$ 24,488,618	$ 22,324,485	$ 22,803,512	$ 14,941,251	$ 9,733,561	$ 16,041,209	$ 198,141,180

Coal Fueled Generating Unit	January 2021
Cholla Unit 1	$ 689,798
Cholla Unit 3	$ 938,346
Total Cholla Coal Costs	$ 1,628,144
Four Corners Unit 4	$ 8,983,022
Four Corners Unit 5	$ 7,787,654
Total Four Corners Coal Costs	$ 16,770,676
Navajo Unit 1	$ 29,512
Navajo Unit 2	$ 30,071
Navajo Unit 3	$ 29,417
Total Navajo Coal Costs	$ 89,000
Total January 2021 Coal Expense	$ 18,487,820

Source: Staff Data Request 1.95 - Confidential PSA workpapers on the Fuel Expense tab

We reviewed the monthly confidential PSA workpapers electronically in Excel for the categories of fuel costs noted above and tied the amounts back to APS fuel expense reports. No exceptions were noted.

As previously noted, the Company retired Navajo Units 1-3 during the fourth quarter of 2019. Accordingly, beginning in November 2019, the monthly coal costs for Navajo decreased significantly as shown in the exhibit above. However, beginning in March 2020 and continuing through January 2021, the Company's fuel expense reports (and shown in the above exhibit) included monthly costs for Navajo totaling $89,000 ($29,512 – Unit 1, $30,071 – Unit 2 and $29,417 – Unit 3). In response to our inquiry regarding these charges, the Company stated that the $89,000 monthly charge to the Navajo units reflects the amortization of a previously paid settlement[44], which has been allocated to final reclamation costs for Navajo. In addition, final reclamation costs are recovered through the PSA with the amortization of these costs aligned to APS's most recent rate case, which is scheduled to be complete in April 2026. The Company included a monthly amortization schedule in its response to Staff data request 9.1, which showed the monthly amortization through April 2026. We noted that beginning in December 2021, which is beyond the review period, the Navajo monthly amortization increased from $89,000 to $248,000. In its response to Staff data request 9.1, APS stated that this increase in the

[44] Per the response to Staff data request 1.18, a settlement involving Navajo was negotiated with Peabody as part of their final settlement agreement.

amortization is due to an increase in final reclamation costs between the original estimate from the Company's 2016 rate case as compared to the final reclamation costs requested during APS's 2019 rate case.

The actual monthly coal generated at the Cholla, Four Corners and Navajo generating plants that is associated with the monthly coal costs shown in Exhibit 4-20 are summarized in the exhibit below:

Exhibit 4-21
Summary of Monthly Coal Generation (in MWh) at the Cholla, Four Corners and Navajo generation plants during the period January 2019 through January 2021

Coal Fueled Generating Unit	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Cholla Unit 1	17,627	(523)	(284)	(166)	2,459	27,192	44,973	43,281	34,593	32,597	45,597	43,716	291,061
Cholla Unit 3	41,900	76,632	96,491	99,923	42,098	66,843	121,152	114,957	70,738	44,126	118,289	113,820	1,006,969
Total Cholla Net Generated MWh	59,527	76,108	96,207	99,757	44,557	94,035	166,125	158,238	105,331	76,723	163,886	157,536	1,298,030
Four Corners Unit 4	283,575	283,126	83,966	190,880	244,741	269,219	311,465	313,184	272,592	282,583	263,199	236,903	3,035,432
Four Corners Unit 5	244,596	248,167	75,817	264,681	148,544	273,670	291,332	292,354	237,594	128,566	172,994	139,791	2,518,105
Total Four Corners Net Generated MWh	528,172	531,293	159,782	455,561	393,285	542,889	602,797	605,538	510,186	411,149	436,193	376,694	5,553,537
Navajo Unit 1	26,857	43,037	35,519	25,483	34,538	38,572	54,745	59,632	57,078	39,056	22,019	-	436,536
Navajo Unit 2	32,103	42,239	19,807	35,750	47,321	29,701	42,546	59,411	50,636	40,580	36,410	-	436,504
Navajo Unit 3	34,587	42,131	46,101	36,455	43,564	43,553	50,996	59,798	38,122	-	-	-	395,307
Total Navajo Net Generated MWh	93,547	127,407	101,427	97,688	125,423	111,826	148,287	178,841	145,836	79,636	58,429	-	1,268,347
Total 2019 Net Generated MWh - Coal	681,245	734,808	357,417	653,006	563,265	748,750	917,209	942,617	761,352	567,508	658,507	534,230	8,119,914

Coal Fueled Generating Unit	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Cholla Unit 1	34,687	11,295	33,182	11,286	34,508	47,420	51,693	63,424	50,855	35,994	20,065	4,473	398,879
Cholla Unit 3	92,637	49,169	82,998	65,560	84,248	109,441	124,445	153,264	125,043	112,451	61,177	16,639	1,077,072
Total Cholla Net Generated MWh	127,324	60,464	116,180	76,846	118,756	156,861	176,138	216,687	175,898	148,444	81,241	21,112	1,475,951
Four Corners Unit 4	176,022	240,782	274,239	263,003	59,449	108,513	261,712	332,702	325,884	235,432	63,100	211,040	2,551,877
Four Corners Unit 5	286,950	124,982	-	-	167,550	299,430	310,461	232,061	322,899	138,804	135,453	248,943	2,267,533
Total Four Corners Net Generated MWh	462,972	365,764	274,239	263,003	226,999	407,942	572,173	564,763	648,783	374,236	198,554	459,983	4,819,410
Navajo Unit 1	-	-	-	-	-	-	-	-	-	-	-	-	-
Navajo Unit 2	-	-	-	-	-	-	-	-	-	-	-	-	-
Navajo Unit 3	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Navajo Net Generated MWh	-	-	-	-	-	-	-	-	-	-	-	-	-
Total 2020 Net Generated MWh - Coal	590,295	426,228	390,419	339,849	345,755	564,803	748,311	781,450	824,681	522,680	279,795	481,095	6,295,361

Coal Fueled Generating Unit	January 2021
Cholla Unit 1	28,658
Cholla Unit 3	36,762
Total Cholla Net Generated MWh	65,419
Four Corners Unit 4	292,976
Four Corners Unit 5	250,176
Total Four Corners Net Generated MWh	543,152
Navajo Unit 1	-
Navajo Unit 2	-
Navajo Unit 3	-
Total Navajo Net Generated MWh	-
Total January 2021 Net Generated MWh - Coal	608,571

Source: Staff Data Request 1.95 - Confidential PSA workpapers on the Gen Details tab

Pursuant to the retirement of Navajo Units 1-3 during October and November of 2019, beginning in December 2019 and continuing through January 2021, there was no coal generated at Navajo Units 1-3 as shown in the exhibit above.

Using the coal cost and generation data from the previous two exhibits, we calculated the coal cost per kWh for Cholla, Four Corners and Navajo as summarized in the table below:

Exhibit 4-22
Summary of Coal Cost per kWh at the Cholla, Four Corners and Navajo generation plants during the period January 2019 through January 2021

Coal Fueled Generating Unit	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Cholla Unit 1 Cost Per kWh (¢/kWh)	$ 3.74	N/A	N/A	N/A	$ 15.01	$ 3.42	$ 2.83	$ 3.00	$ 3.07	$ 3.18	$ 2.92	$ 2.97	$ 3.37
Cholla Unit 3 Cost Per kWh (¢/kWh)	$ 3.92	$ 3.06	$ 3.13	$ 3.12	$ 4.16	$ 3.38	$ 2.94	$ 2.98	$ 3.24	$ 3.82	$ 2.93	$ 3.06	$ 3.18
Total Cholla Cost Per kWh (¢/kWh)	$ 7.66	$ 3.06	$ 3.13	$ 3.12	$ 19.17	$ 6.80	$ 5.76	$ 5.98	$ 6.31	$ 7.00	$ 5.85	$ 6.03	$ 6.55
Four Corners Unit 4 Cost Per kWh (¢/kWh)	$ 2.96	$ 2.91	$ 3.49	$ 2.97	$ 2.74	$ 2.85	$ 3.00	$ 3.02	$ 3.00	$ 3.11	$ 3.10	$ 4.31	$ 3.09
Four Corners Unit 5 Cost Per kWh (¢/kWh)	$ 2.97	$ 2.93	$ 3.62	$ 2.97	$ 2.78	$ 2.88	$ 3.03	$ 3.07	$ 3.18	$ 3.25	$ 3.21	$ 5.08	$ 3.15
Total Four Corners Cost Per kWh (¢/kWh)	$ 5.93	$ 5.84	$ 7.11	$ 5.94	$ 5.52	$ 5.73	$ 6.04	$ 6.10	$ 6.18	$ 6.36	$ 6.31	$ 9.39	$ 6.24
Navajo Unit 1 Cost Per kWh (¢/kWh)	$ 3.64	$ 2.31	$ 2.34	$ 5.00	$ 3.23	$ 2.29	$ 2.31	$ 3.72	$ 2.70	$ 3.41	$ 0.68	$ -	$ 2.91
Navajo Unit 2 Cost Per kWh (¢/kWh)	$ 3.11	$ 2.40	$ 4.27	$ 3.63	$ 2.40	$ 3.03	$ 3.03	$ 3.80	$ 3.11	$ 3.35	$ 0.42	$ -	$ 2.97
Navajo Unit 3 Cost Per kWh (¢/kWh)	$ 2.82	$ 2.35	$ 1.80	$ 3.48	$ 2.55	$ 2.02	$ 2.47	$ 3.70	$ 4.04	$ -	$ -	$ -	$ 3.20
Total Navajo Cost Per kWh (¢/kWh)	$ 9.57	$ 7.05	$ 8.41	$ 12.11	$ 8.17	$ 7.33	$ 7.81	$ 11.22	$ 9.85	$ 6.76	$ 1.09	$ -	$ 9.08
Total 2019 Cost Per kWh (¢/kWh)	$ 23.15	$ 15.95	$ 18.65	$ 21.17	$ 32.87	$ 19.87	$ 19.61	$ 23.30	$ 22.33	$ 20.12	$ 13.26	$ 15.42	$ 21.87

Coal Fueled Generating Unit	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Cholla Unit 1 Cost Per kWh (¢/kWh)	$ 3.41	$ 4.18	$ 3.48	$ 4.74	$ 3.22	$ 2.97	$ 2.75	$ 2.63	$ 2.66	$ 2.99	$ 4.00	$ 10.35	$ 3.17
Cholla Unit 3 Cost Per kWh (¢/kWh)	$ 3.18	$ 3.72	$ 3.36	$ 3.43	$ 3.22	$ 2.93	$ 2.91	$ 2.64	$ 2.64	$ 2.98	$ 3.42	$ 7.33	$ 3.10
Total Cholla Cost Per kWh (¢/kWh)	$ 6.59	$ 7.90	$ 6.84	$ 8.18	$ 6.45	$ 5.90	$ 5.66	$ 5.27	$ 5.29	$ 5.97	$ 7.42	$ 17.67	$ 6.27
Four Corners Unit 4 Cost Per kWh (¢/kWh)	$ 3.90	$ 3.47	$ 3.05	$ 2.97	$ 4.10	$ 3.14	$ 3.26	$ 2.91	$ 2.74	$ 2.78	$ 3.62	$ 3.13	$ 3.13
Four Corners Unit 5 Cost Per kWh (¢/kWh)	$ 3.64	$ 3.83	$ -	$ -	$ 3.46	$ 2.76	$ 3.49	$ 2.95	$ 2.83	$ 2.80	$ 3.29	$ 3.08	$ 3.15
Total Four Corners Cost Per kWh (¢/kWh)	$ 7.54	$ 7.30	$ 3.05	$ 2.97	$ 7.56	$ 5.90	$ 6.75	$ 5.86	$ 5.57	$ 5.58	$ 6.92	$ 6.21	$ 6.28
Navajo Unit 1 Cost Per kWh (¢/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Navajo Unit 2 Cost Per kWh (¢/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Navajo Unit 3 Cost Per kWh (¢/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total Navajo Cost Per kWh (¢/kWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total 2020 Cost Per kWh (¢/kWh)	$ 14.13	$ 15.21	$ 9.89	$ 11.15	$ 14.01	$ 11.80	$ 12.41	$ 11.13	$ 10.86	$ 11.54	$ 14.34	$ 23.88	$ 12.55

Coal Fueled Generating Unit	January 2021
Cholla Unit 1 Cost Per kWh (¢/kWh)	$ 2.41
Cholla Unit 3 Cost Per kWh (¢/kWh)	$ 2.55
Total Cholla Cost Per kWh (¢/kWh)	$ 4.96
Four Corners Unit 4 Cost Per kWh (¢/kWh)	$ 3.07
Four Corners Unit 5 Cost Per kWh (¢/kWh)	$ 3.11
Total Four Corners Cost Per kWh (¢/kWh)	$ 6.18
Navajo Unit 1 Cost Per kWh (¢/kWh)	$ -
Navajo Unit 2 Cost Per kWh (¢/kWh)	$ -
Navajo Unit 3 Cost Per kWh (¢/kWh)	$ -
Total Navajo Cost Per kWh (¢/kWh)	$ -
Total January 2021 Cost Per kWh (¢/kWh)	$ 11.14

Source: Staff Data Request 1.95 - Confidential PSA workpapers on the Generation (2) tab

We compared our calculations of the coal costs per kWh to the Company's calculations in its confidential PSA workpapers. No exceptions were noted.

We attempted to tie the total 2019 and 2020 fuel costs to the Company's respective 2019 and 2020 FERC Form 1 filings. However, we were unable to directly tie the total year-end fuel costs reflected in the monthly confidential PSA workpapers to APS's FERC Form 1 filings as shown in the exhibit below:

Exhibit 4-23
Comparison of Fuel Costs in PSA Workpapers to FERC Form 1 Filings

Fuel Expense Per PSA Workpapers	Total 2019	FERC Form 1	2019 Amount	Difference
Gas Generation Fuel Expense	$211,107,743			
Gas Generation Fuel Expense under Tolling Arrangements	$ 19,643,082			
Gas Hedges and Mark-to-Market Expense	$ 57,562,050			
Oil Generation Fuel Expense	$ 889,708			
Coal Generation Fuel Expense	$269,964,711	Fuel - FERC 501	$271,514,352	
Nuclear Generation Fuel Expense	$ 67,152,175	Fuel - FERC 518	$ 67,152,175	
Owned Renewable Generation	$ -	Fuel - FERC 547	$270,075,955	
Total Fuel Expense in PSA Workpapers	$626,319,468	Total Fuel Costs in FERC Form 1	$608,742,482	$ 17,576,986

Fuel Expense Per PSA Workpapers	Total 2020	FERC Form 1	2020 Amount	Difference
Gas Generation Fuel Expense	$237,637,050			
Gas Generation Fuel Expense under Tolling Arrangements	$ 25,171,714			
Gas Hedges and Mark-to-Market Expense	$ (2,651,219)			
Oil Generation Fuel Expense	$ 1,367,936			
Coal Generation Fuel Expense	$216,626,251	Fuel - FERC 501	$216,626,250	
Nuclear Generation Fuel Expense	$ 65,811,811	Fuel - FERC 518	$ 65,811,812	
Owned Renewable Generation	$ -	Fuel - FERC 547	$317,732,099	
Total Fuel Expense in PSA Workpapers	$543,963,543	Total Fuel Costs in FERC Form 1	$600,170,161	$ (56,206,618)

As shown in the above exhibit, for 2019 there was a $17,576,986 difference between the monthly confidential PSA workpapers and the 2019 FERC Form 1. For 2020, there was a ($56,206,618) difference between the PSA workpapers and the 2020 FERC Form 1. We asked APS to provide a reconciliation of the Company's overall 2019 and 2020 fuel costs from the confidential monthly PSA workpapers to the respective 2019 and 2020 FERC Form 1 filings.[45] In its response to Staff data request 7.1, the Company provided the requested reconciliations for 2019 and 2020 shown in the exhibit below:

[45] See Staff data request 7.1 and Staff data request 7.2.

Exhibit 4-24
Reconciliation of Fuel Costs in PSA Workpapers to FERC Form 1 Filings

		Fuel Costs from FERC FORM 1					
Reporting Period	PSA Summary Page	501	518	547	547.5	Total	PSA to FERC Form 1 Delta
Jan-2019	$ 38,512,911	$ 22,708,182	$ 6,084,893	$ 9,719,836	$ 11,196,365	$ 49,709,276	$ (11,196,364)
Feb-2019	$ 40,084,642	$ 22,624,616	$ 5,432,648	$ 12,027,379	$ 5,822,259	$ 45,906,902	$ (5,822,260)
Mar-2019	$ 40,019,182	$ 13,033,258	$ 6,069,283	$ 20,916,641	$ (3,149,398)	$ 36,869,784	$ 3,149,398
Apr-2019	$ 44,174,081	$ 22,329,928	$ 4,018,255	$ 17,825,898	$ (4,676,397)	$ 39,497,685	$ 4,676,397
May 2019	$ 47,751,610	$ 18,012,361	$ 5,532,079	$ 24,207,170	$ (7,548,153)	$ 40,203,457	$ 7,548,153
Jun-2019	$ 61,518,739	$ 23,054,423	$ 5,940,639	$ 32,523,677	$ (11,211,184)	$ 50,307,555	$ 11,211,184
Jul-2019	$ 66,969,392	$ 28,429,614	$ 6,159,376	$ 32,380,403	$ (1,350,390)	$ 65,619,003	$ 1,350,389
Aug-2019	$ 77,304,541	$ 31,479,569	$ 5,857,234	$ 39,967,738	$ (6,859,864)	$ 70,444,677	$ 6,859,864
Sep-2019	$ 59,091,800	$ 25,347,542	$ 5,641,328	$ 28,102,930	$ 1,868,264	$ 60,960,064	$ (1,868,264)
Oct-2019	$ 37,080,969	$ 21,395,382	$ 4,247,658	$ 11,437,929	$ 14,674,650	$ 51,755,619	$ (14,674,650)
Nov-2019	$ 47,516,317	$ 19,344,096	$ 5,868,817	$ 22,303,404	$ (5,033,653)	$ 42,482,663	$ 5,033,653
Dec-2019	$ 66,295,283	$ 23,755,382	$ 6,299,962	$ 36,239,939	$ (11,309,485)	$ 54,985,798	$ 11,309,485
Total 2019	$ 626,319,468	$ 271,514,352	$67,152,175	$ 287,652,942	$ (17,576,986)	$ 608,742,482	$ 17,576,986
Jan-2020	$ 71,551,941	$ 22,990,511	$ 6,300,381	$ 42,261,048	$ (20,030,126)	$ 51,521,814	$ 20,030,126
Feb-2020	$ 52,014,709	$ 16,564,979	$ 5,330,295	$ 30,119,435	$ (11,885,486)	$ 40,129,223	$ 11,885,486
Mar-2020	$ 14,617,435	$ 13,785,540	$ 5,946,541	$ (5,114,647)	$ 20,052,570	$ 34,670,005	$ (20,052,570)
Apr-2020	$ (10,208,336)	$ 11,899,340	$ 4,265,743	$ (26,373,419)	$ 46,573,327	$ 36,364,991	$ (46,573,327)
May 2020	$ 64,036,635	$ 13,364,816	$ 5,794,002	$ 44,877,817	$ (19,878,278)	$ 44,158,357	$ 19,878,278
Jun-2020	$ 66,035,915	$ 18,277,797	$ 5,944,903	$ 41,813,215	$ (10,495,500)	$ 55,540,415	$ 10,495,500
Jul-2020	$ 44,423,259	$ 25,802,934	$ 6,159,650	$ 12,460,675	$ 30,272,263	$ 74,695,521	$ (30,272,263)
Aug-2020	$ 25,126,493	$ 23,523,289	$ 6,210,497	$ (4,607,293)	$ 47,194,551	$ 72,321,043	$ (47,194,550)
Sep-2020	$ 71,675,375	$ 24,312,293	$ 5,996,539	$ 41,366,543	$ (8,729,709)	$ 62,945,666	$ 8,729,709
Oct-2020	$ 4,317,903	$ 16,806,318	$ 4,501,199	$ (16,989,614)	$ 41,245,748	$ 45,563,651	$ (41,245,748)
Nov-2020	$ 72,530,531	$ 10,807,149	$ 3,657,090	$ 58,066,291	$ (36,273,281)	$ 36,257,250	$ 36,273,281
Dec-2020	$ 67,841,684	$ 18,491,284	$ 5,704,969	$ 43,645,431	$ (21,839,461)	$ 46,002,223	$ 21,839,461
Total 2020	$ 543,963,543	$ 216,626,250	$65,811,812	$ 261,525,481	$ 56,206,618	$ 600,170,160	$ (56,206,617)

Source: Staff Data Request 7.1

As shown in the above exhibit, the furthermost column on the right shows the aforementioned differences of $17,576,986 and ($56,206,617) for 2019 and 2020, respectively. In response Staff data request 7.1, the Company stated that variance between the 2019 PSA workpapers and 2019 FERC Form 1 fuel expense amounts is the deferred mark-to-market exclusions.[46] As part of its reconciliation, the Company provided screenshots from its general ledger from which we tied the monthly mark-to-market exclusions listed in the exhibit above. No exceptions were noted.

For January 2021, we tied the fuel costs from the Company's PSA workpapers to the monthly fuel expense reports. No exceptions were noted.

<u>Conclusion</u>

With the Company's explanations and reconciliations shown above coupled with tying amounts to the fuel expense reports and FERC Form 1 filings, we conclude that APS's fuel costs were accurately stated for the review period.

[46] The response to Staff data request 7.2 provided a similar explanation for the 2020 variance of ($56,206,618).

Review Related To Purchased Power

Pursuant to the PSA POA, purchased power costs are among the includable costs in the PSA with such costs being recorded in FERC Account 555. In the Company's confidential monthly PSA workpapers (discussed in more detail later in this report), APS breaks out purchased power costs by Long-Term Purchased Power Expense, Market Purchased Power Expense and Other Purchased Power Expense on the Energy Transactions tab.

We reviewed the monthly confidential PSA workpapers electronically in Excel for the three categories of purchased power costs and tied the amounts back to two tabs titled "Level 3" and "Level 3 Tie Out".[47] No exceptions were noted. We then attempted to tie the total 2019 and 2020 purchased power costs to the Company's respective 2019 and 2020 FERC Form 1 filings. However, we were unable to directly tie the total year-end purchased power costs reflected in the monthly confidential PSA workpapers to APS's FERC Form 1 filings as shown in the exhibit below:

Exhibit 4-25
Comparison of Purchased Power Costs in PSA Workpapers to FERC Form 1 Filings

			2019	
		Purchased Power per FERC Form 1	**Amount**	**Difference**
	2019	Purchased Power - FERC 555	$ 405,183,195	
Purchased Power per PSA Workpapers	**Amount**	Other Expenses - FERC 557	$ 3,690,238	
Long-Term Purchased Power Expense	$ 289,046,925	Transmission of Electricity by Others - FERC 565	$ 33,978,850	
Market Purchased Power Expense	$ 139,294,242	Allowances - FERC 509	$ 3,687,274	
Other Purchased Power Expense	$ 40,183,333	NL Wheel - FERC 456.9	$ (648,481)	
Total Purchased Power	$ 468,524,500	Total Purchased Power	$ 445,891,076	$ 22,633,423

			2020	
		Purchased Power per FERC Form 1	**Amount**	**Difference**
	2020	Purchased Power - FERC 555	$ 361,383,944	
Purchased Power per PSA Workpapers	**Amount**	Other Expenses - FERC 557	$ 3,436,452	
Long-Term Purchased Power Expense	$ 318,300,986	Transmission of Electricity by Others - FERC 565	$ 37,915,120	
Market Purchased Power Expense	$ 143,357,853	Allowances - FERC 509	$ 3,185,982	
Other Purchased Power Expense	$ 46,031,771	NL Wheel - FERC 456.9	$ (297,529)	
Total Purchased Power	$ 507,690,609	Total Purchased Power	$ 405,623,969	$ 102,066,640

As shown in the above exhibit, for 2019 there was a $22,633,423 difference between the monthly confidential PSA workpapers and the 2019 FERC Form 1. For 2020, there was a $102,066,640 difference between the PSA workpapers and the 2020 FERC Form 1. We asked APS to provide a reconciliation of the Company's overall 2019 and 2020 purchased power costs from the confidential monthly PSA workpapers to the respective 2019 and 2020 FERC Form 1 filings.[48] In its response to Staff data request 7.1, the Company provided the requested reconciliations for 2019 and 2020 shown in the exhibit below:

[47] According to the response to Staff data request 1.97, the Level 3 and Level 3 Tie Out tabs in the confidential PSA workpapers reflect APS's general ledger detail for each account that contain costs and/or revenues included in the Company's monthly PSA filings for each month of the review period.

[48] See Staff data request 7.1 and Staff data request 7.2.

Exhibit 4-26
Reconciliation of Purchased Power Costs in PSA Workpapers to FERC Form 1 Filings

		Purchased Power FERC Form 1								
Reporting Period	PSA Summary Page	555	557 (Other PP)	557.1 (Broker Fees)	565 (NL Wheel)	565.6 (Sys Excess Wheel)	509.3 (Carbon)	456.9 (NL Wheel)	Total FERC	PSA to FERC Form 1 Delta
Jan-2019	$ 17,800,683	$ 25,141,880	$ 234,737	$ 40,318	$ 2,110,829	$ 43,804	$ 147,332	$ (46,167)	$ 27,672,733	$ (9,872,050)
Feb-2019	$ 19,831,110	$ 31,169,957	$ 230,145	$ 16,463	$ 2,061,911	$ 43,459	$ 445,490	$ (43,459)	$ 33,923,967	$ (14,092,857)
Mar-2019	$ 32,578,760	$ 34,900,311	$ 453,286	$ 11,757	$ 3,063,621	$ 44,006	$ 363,048	$ (50,155)	$ 38,785,874	$ (6,207,114)
Apr-2019	$ 37,353,284	$ 26,031,612	$ 534,445	$ 29,903	$ 2,054,485	$ 42,290	$ 5,136	$ (79,085)	$ 28,618,787	$ 8,734,497
May 2019	$ 42,226,662	$ 26,309,388	$ 253,531	$ 23,409	$ 2,204,214	$ 42,416	$ 187,314	$ (42,416)	$ 28,977,856	$ 13,248,806
Jun-2019	$ 58,264,771	$ 45,561,963	$ 135,432	$ 8,716	$ 2,740,709	$ 42,348	$ 228,541	$ (42,324)	$ 48,675,385	$ 9,589,386
Jul-2019	$ 62,282,993	$ 53,475,153	$ 216,783	$ 22,040	$ 3,126,094	$ 49,715	$ 362,495	$ (51,035)	$ 57,201,245	$ 5,081,749
Aug-2019	$ 61,507,719	$ 52,344,533	$ 251,821	$ 18,170	$ 3,408,542	$ 48,781	$ 395,223	$ (48,781)	$ 56,418,288	$ 5,089,430
Sep-2019	$ 47,269,731	$ 40,288,836	$ 349,457	$ 17,641	$ 3,445,786	$ 47,165	$ 493,476	$ (47,165)	$ 44,595,197	$ 2,674,534
Oct-2019	$ 38,247,198	$ 27,836,852	$ 266,299	$ 22,688	$ 3,397,975	$ 44,145	$ 420,272	$ (48,926)	$ 31,939,306	$ 6,307,892
Nov-2019	$ 27,432,449	$ 21,169,297	$ 231,524	$ 22,030	$ 2,657,255	$ 43,248	$ 237,192	$ (43,248)	$ 24,317,298	$ 3,115,152
Dec-2019	$ 23,729,139	$ 20,953,411	$ 281,165	$ 18,477	$ 3,173,348	$ 42,703	$ 401,757	$ (105,721)	$ 24,765,140	$ (1,036,001)
Total 2019	$ 468,524,500	$ 405,183,195	$ 3,438,625	$ 251,613	$ 33,444,770	$ 534,080	$3,687,274	$ (648,481)	$ 445,891,077	$ 22,633,423
Jan-2020	$ 20,697,455	$ 14,787,006	$ 215,340	$ 83,017	$ 3,960,264	$ 44,350	$ 150,525	$ (74,105)	$ 19,166,397	$ 1,531,058
Feb-2020	$ 22,000,126	$ 17,843,992	$ 247,185	$ 26,900	$ (143,487)	$ 46,730	$ 173,165	$ (49,993)	$ 18,144,492	$ 3,855,634
Mar-2020	$ 26,255,417	$ 21,962,511	$ 246,843	$ 23,553	$ 2,558,902	$ 45,870	$ 140,128	$ (45,864)	$ 24,931,942	$ 1,323,475
Apr-2020	$ 32,584,979	$ 24,475,757	$ 240,944	$ 37,266	$ 3,112,410	$ 42,577	$ 34,818	$ (49,104)	$ 27,894,669	$ 4,690,310
May 2020	$ 39,271,432	$ 34,335,884	$ 206,813	$ 73,174	$ 2,686,934	$ 45,806	$ 65,568	$ (45,806)	$ 37,368,371	$ 1,903,061
Jun-2020	$ 59,269,405	$ 37,169,628	$ 205,318	$ 23,746	$ 3,162,064	$ (45,806)	$ 107,752	$ 45,806	$ 40,668,507	$ 18,600,898
Jul-2020	$ 62,870,215	$ 36,387,338	$ 246,305	$ 26,390	$ 3,465,771	$ -	$1,019,985	$ 272	$ 41,146,062	$ 21,724,153
Aug-2020	$ 81,773,247	$ 54,912,436	$ 220,999	$ 29,394	$ 4,110,019	$ -	$ 577,313	$ (43,084)	$ 59,807,078	$ 21,966,169
Sep-2020	$ 60,711,689	$ 41,014,776	$ 306,465	$ 25,253	$ 7,227,123	$ -	$ 266,323	$ 23,234	$ 48,863,174	$ 11,848,515
Oct-2020	$ 43,446,416	$ 34,380,796	$ 249,211	$ 31,410	$ 1,876,012	$ -	$ 379,529	$ 85	$ 36,917,043	$ 6,529,374
Nov-2020	$ 31,308,140	$ 25,251,516	$ 203,927	$ 75,071	$ 3,215,053	$ -	$ 23,022	$ 21,575	$ 28,790,164	$ 2,517,976
Dec-2020	$ 27,502,089	$ 18,862,303	$ 364,046	$ 27,883	$ 2,504,530	$ -	$ 247,855	$ (80,546)	$ 21,926,071	$ 5,576,018
Total 2020	$ 507,690,609	$ 361,383,944	$ 2,953,395	$ 483,057	$ 37,735,594	$ 179,527	$3,185,982	$ (297,529)	$ 405,623,969	$ 102,066,640

Source: Staff Data Request 7.1

As shown in the above exhibit, the furthermost column on the right shows the aforementioned differences of $22,633,423 and $102,066,640 for 2019 and 2020, respectively. In response Staff data request 7.1, the Company stated that variance between the 2019 PSA workpapers and 2019 FERC Form 1 purchased power amounts is monthly broker fees booked to FERC Account 557.1 and monthly PSA deferral expense booked to FERC Account 555.7.[49] The exhibit below provides a breakout by month of the broker fees and PSA deferral expense that comprise the differences noted above between the PSA workpapers and FERC Form 1 filings:

[49] The response to Staff data request 7.2 gave a similar explanation for the 2020 variance of $102,066,640.

Exhibit 4-27
Monthly Breakout of Broker Fees and PSA Deferral Expense

2019 Variance by FERC Account					
555.7 (PSA Deferrals)		557 (Non-Broker Fees)		Total	
$	(9,637,314)	$	(234,737)	$	(9,872,050)
$	(13,858,283)	$	(230,145)	$	(14,088,428)
$	(5,753,828)	$	(453,286)	$	(6,207,115)
$	9,268,941	$	(534,445)	$	8,734,496
$	13,502,337	$	(253,531)	$	13,248,806
$	9,724,818	$	(135,432)	$	9,589,386
$	5,298,532	$	(216,783)	$	5,081,749
$	5,341,252	$	(251,821)	$	5,089,430
$	3,023,990	$	(349,457)	$	2,674,533
$	6,574,192	$	(266,299)	$	6,307,893
$	3,346,676	$	(231,524)	$	3,115,152
$	(754,837)	$	(281,165)	$	(1,036,001)
$	26,076,477	$	(3,438,625)	$	22,637,852
		PSA to FERC Form 1 Delta		$	22,633,423
		Immaterial Difference		$	4,429
2020 Variance by FERC Account					
555.7 (PSA Deferrals)		557 (Non-Broker Fees)		Total	
$	1,746,397	$	(215,340)	$	1,531,057
$	4,102,819	$	(247,185)	$	3,855,634
$	1,570,318	$	(246,843)	$	1,323,475
$	4,931,255	$	(240,944)	$	4,690,311
$	2,109,873	$	(206,813)	$	1,903,061
$	18,806,217	$	(205,318)	$	18,600,899
$	21,970,459	$	(246,305)	$	21,724,154
$	22,187,169	$	(220,999)	$	21,966,170
$	12,154,979	$	(306,465)	$	11,848,515
$	6,778,585	$	(249,211)	$	6,529,374
$	2,721,904	$	(203,927)	$	2,517,977
$	5,940,064	$	(364,046)	$	5,576,018
$	105,020,039	$	(2,953,395)	$	102,066,644
		PSA to FERC Form 1 Delta		$	102,066,640
		Immaterial Difference		$	4
Source: Staff Data Request 7.1					

As shown in the above exhibit, there were variances of $4,429 and $4 for 2019 and 2020, respectively, which we consider to be immaterial. We tied the amounts above to the general ledger detail. No exceptions were noted.

For January 2021, we tied the purchased power costs shown on the Energy Transactions tab to the general ledger detail reflected on the Level 3 and Level 3 Tie Out tabs. No exceptions were noted.

Conclusion

With the Company's explanations and reconciliations shown above coupled with tying amounts to the general ledger and FERC Form 1 filings, we conclude that APS's purchased power costs are generally accurately stated.

Review Related to Service Interruptions And Unscheduled Outages

Documentation relating to the review of Service Interruptions, Unplanned Outages and Planned Maintenance includes APS's responses to Staff data request 1.43, Staff data request 1.44, Staff data request 1.121, Staff data request 1.122, Staff data request 1.123 and Staff data request 1.124.

Staff data request 1.43 inquired about instances in which customers' power supplies were interrupted during the review period January 2019 through January 2021. In response, the Company stated that during the review period, there was no customer outages due to a lack of power supply.[50]

As it relates to planned maintenance or overhead outages as well as unplanned outages at any of the Company's coal-fueled generating plants during the review period, in its responses to Staff data request 1.121 and Staff data request 1.122, APS referred to the response to Staff data request 1.44. As it relates to unplanned outages, the Company stated that it uses a model to forecast the probable number of unplanned outages that are likely to occur in order to manage coal inventory levels. For planned maintenance or overhead outages, APS forecasts maintenance outages to occur in planning models that are used to manage coal inventory levels.[51] In addition, the Company stated:

> Any deviations to the planned inventory levels are managed through annual coal nominations governed by the coal supply agreements. Four Corners is a mine mouth operation where APS does not take possession of coal inventory, so inventory levels are managed by the mine to a contractual level. Cholla uses annual nominations to manage inventory forecast deviations. APS was not involved in the management of inventory for the Navajo Generating Station, which was operated by SRP.[52]

Staff data request 1.44 requested that APS identify instances during the review period in which the Company's generating units experienced unscheduled outages and to provide documentation concerning the following:

1. The cause(s) of the outage, including whether APS conducted a root-cause analysis.
2. Steps taken by the Company to minimize the impacts of the unscheduled outage.
3. Efforts made to secure replacement power, if applicable.
4. The methodology employed to price the replacement power, if applicable.
5. The cost impacts resulting from the periods during which the unscheduled outage occurred.

[50] According to the response to Staff data request 1.123, APS also stated that no coal supply interruptions occurred during the 2019, 2020 and January 2021 review period.
[51] See the response to Staff data request 1.122.
[52] See the responses to Staff data request 1.121 and Staff data request 1.122.

In response to item 1, APS provided an Excel attachment titled "Event Report", which provided a list of the unscheduled outages that occurred during the period January 2019 through January 2021 at the following generating units: Cholla, Four Corners, Palo Verde, Redhawk, West Phoenix, Ocotillo, Saguaro, Sundance and Yucca.

The Event Report, which is voluminous, is organized by the column headings shown in the following exhibit:

Exhibit 4-28
Column Headings of Event Report Detailing Unplanned Outages at APS's Generating Units

Event Number	Unit	Event Start	Event End	Event Type	Cause Code	Component	Cause Code Name	Event Description	Eq Hrs	Eq MWh

As shown in the above exhibit, the Event Report is organized by: Event Number, Unit, Event Start, Event End, Event Type, Cause Code, Component, Cause Code Name, Event Description, Eq Hours, and Eq MWh. With regard to the Cause Code and Cause Code Name columns, a second tab on the Event Report Excel file titled "Cause Code Descriptions" includes a comprehensive listing of the Cause Codes. This voluminous listing is comprised of over 13,000 line items and is organized by following column headings:

Exhibit 4-29
Column Headings of Cause Codes Related to Unplanned Outages at APS's Generating Units

Unit Type Code	Unit Type Name	Cause Code ID	System Name	Component Name	Sub-Component Name	Cause Code Name

On a test basis, we compared the Cause Codes and Cause Code Names from the Case Code Descriptions tab to what is reflected on individual line items on the Event Report and noted no exceptions. Using Cholla Unit 1 as an illustrative example, an unplanned outage on the Event Report with an Event Start date of June 28, 2019, and an Event End date of June 29, 2019, stated "feeder leveling gate on B" mill was broken 1b" under the Event Description column. This event was assigned Cause Code 320 and has the Cause Code Name "Foreign Object in Pulverizer's Mill", which we traced back to the Cause Code Descriptions listing. No exceptions were noted.

With regard to APS conducting root-cause analyses for its unplanned outages during the review period, the Company provided three additional attachments in response to Staff data request 1.44 titled (1) 2019 Summer Event Summary, (2) 2020 Summer Event Summary, and (3) 2020-2021 Winter Event Summary. These documents listed the same unplanned outages that are included on the Event Report. APS asserted that the Event Summary documents included the corrective actions taken and lessons learned from the unplanned outages. For example, with regard to the outage event discussed above with regard to Cholla Unit 1 (i.e., Cause Code 320), the 2019 Summer Event Summary document stated the following:

Corrective Actions: Repaired the leveling gate for 1B mill and then cleaned out mill, pyrite section and associated coal piping. Used a vacuum truck to expede the cleaning process.

Lessons Learned: This is the second leveling gate issue for the unit in the past few weeks. Coal yard does report some large chunks of coal and some rocks coming in from the mine. We are also performing a top to bottom walkdown inspection of the #1 Crusher Tower to ensure all components are in proper order.

As it relates to efforts APS has made to minimize the impacts of unplanned outages, the Company stated that it takes the following steps to minimize such outage impacts:

a. Reserves are held on a 24x7 basis to account for unscheduled events as applicable, such as:
    i. Intrahour flexibility;
    ii. Operating reserves; and
    iii. Regulation.
b. Communication between plants and dispatch is maintained on a 24x7 basis to ensure coordination.
c. APS plans and optimizes routine maintenance to ensure assets are maintained.
d. APS manages generating unit wear, including starts and risk.

As it relates to efforts APS has made to secure replacement power (if applicable), the Company stated that in addition to the steps listed above, replacement power is purchased from the market through Day Ahead or Real-Time availability as applicable.

The exhibit below reflects the monthly cost impacts (net of replacement costs) from the unplanned outages that occurred during the review period:

Exhibit 4-30
Monthly Unplanned Outage and Replacement Costs for the Period January 2019 - January 2021

[redacted]

As shown in the exhibit above, [redacted]

We inquired as to why certain unplanned outage costs and replacement costs are positive and other such costs negative. In its response to Staff data request 8.5, APS provided a table which shows in general terms, how to interpret the positive and negative values, which is replicated in the exhibit below:

Exhibit 4-31
Summary of Unplanned Outage Positive and Negative Values

Factor	Negative Values	Positive Values
Outage Duration Variance	Cost savings result from outage durations that are shorter than budgeted	Costs are larger and positive when the duration of unplanned outages are equal to or longer than budgeted outages
Fuel Price Variance	Cost savings result when actual fuel cost is less than budgeted fuel cost	Costs are positive when the fuel prices are equal to or greater than budgeted fuel prices

The Company stated that the treatments summarized in the above exhibit can be applied to any reporting month and that for most months, the results reflect a combination of both factors noted above. In addition, this treatment also applies to the avoided cost, which represents fuel costs not avoided when the generating units are not running due to forced outages at the actual market fuel prices.

With regard to the unplanned outage costs included in the Company's PSA filings, APS stated that the monthly net unplanned outage costs listed in Exhibit 4-30 above reflect all outages (planned and unplanned) for all of APS generation facilities. The costs associated with the unplanned outages that are included in the PSA are reflected on the "Outage Cost" tab of the Company's monthly confidential PSA filings[53] and are broken out by generating facility.

<u>Cholla Plant</u>

The exhibit below shows the unplanned outage costs that were included in the PSA for Cholla during each month of the review period:

[53] See the response to Staff data request 8.5.

Exhibit 4-32
Summary of Unplanned Outage Costs at Cholla from January 2019 through January 2021 – Amounts in $000's

[redacted]

As shown in the exhibit above, the unplanned outage costs are shown as gross replacement cost less avoided costs[54] resulting in actual net replacement cost. [redacted]

Included in the Company's confidential monthly PSA filing workpapers (which are discussed in more detail below), is a tab titled "Outages", which was included in the PSA workpapers to address Item A, number 4 on page 9 of the PSA POA.[56] Specifically, Item A, number 4 is described as follows in the PSA POA:

> Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.

The unplanned outages that occurred at Cholla during 2019 are summarized in the exhibit below:

[54] As indicated in the confidential PSA workpapers (provided in Staff data request 1.95), avoided costs represent the fuel costs that are avoided when the generating units are not running due to unplanned outages.
[55] Cholla Unit 2 was retired in 2016.
[56] See Staff data request 1.138, confidential attachment APS21FA00004, page 7.

Exhibit 4-33
Summary of Unplanned Outages at Cholla from January through December 2019

Line No.	Plant and Unit	Outage Start: Date	Time	Outage End: Date	Time	Outage Type	Description*	Hours
		January 2019						
1	Cholla Unit 1	No Outages						0.00
2	Cholla Unit 3	12-Jan-19	22:23	18-Jan-19	17:00	U1	Unplanned	138.62
		February 2019						
3	Cholla Unit 3	17-Feb-19	12:19	23-Feb-19	19:30	U1	Unplanned	151.18
		March 2019						
4	Cholla Unit 3	09-Mar-19	05:44	14-Mar-19	14:54	U1	Unplanned	129.17
5	Cholla Unit 3	14-Mar-19	15:07	14-Mar-19	17:15	U1	Unplanned	2.13
6	Cholla Unit 3	14-Mar-19	21:58	14-Mar-19	23:15	U1	Unplanned	1.28
		April 2019						
7	Cholla Unit 3	No Outages						
		May 2019						
8	Cholla Unit 1	20-May-19	23:17	21-May-19	04:02	U1	Unplanned	4.75
9	Cholla Unit 3	07-May-19	23:45	08-May-19	00:58	U1	Unplanned	1.22
10	Cholla Unit 3	15-May-19	09:55	16-May-19	06:30	U1	Unplanned	20.58
		June 2019						
11	Cholla Unit 1	No Outages						
12	Cholla Unit 3	No Outages						
		July 2019						
13	Cholla Unit 1	No Outages						
14	Cholla Unit 3	No Outages						
		August 2019						
15	Cholla Unit 3	No Outages						
		September 2019						
16	Cholla Unit 3	No Outages						
		October 2019						
17	Cholla Unit 3	17-Oct-19	04:50	17-Oct-19	16:22	U1	Unplanned	11.53
		November 2019						
18	Cholla Unit 1	07-Nov-19	12:17	07-Nov-19	22:08	U1	Unplanned	9.85
19	Cholla Unit 3	No Outages						
		December 2019						
20	Cholla Unit 1	29-Dec-19	11:12	29-Dec-19	12:21	U1	Unplanned	1.15
21	Total Hours of Unplanned Outages as Cholla in 2019							471.46

Source: Staff Data Request 1.95 from the Outages tab of the Confidential PSA Workpapers

* Outage descriptions conform to the official NERC/GADS outage descriptions. All outages less than 1 hour have been excluded

As shown in the above exhibit, there were unplanned outages at Cholla totaling 471.46 hours during 2019. The most significant unplanned outages were at Unit 3 in January, February and March, which lasted for 138.62 hours, 151.18 hours and 129.17 hours, respectively, and zero unplanned outages from June through September. From October through December 2019, the unplanned outages at Cholla Units 1 and 3 were of a relatively short duration. It should be noted that there were also planned outages and maintenance performed at Cholla during 2019 as well, although the above exhibit reflects only the unplanned outages.

Also included in the Company's confidential monthly PSA filing workpapers is a tab titled "Generation (2)", which was included in the PSA workpapers to address Item A, numbers 1-3 and 5-6 on page 9 of the PSA POA and which compiles information from the Company's

Generation Detail and Fuel Expense worksheets, including: generation, cost, heat rate and EFOF for each unit.[57] Specifically, Item A, numbers -1-3 and 5-6 are described as follows in the PSA POA:

- Item A, number 1: Net generation in MWh per month and 12 months cumulatively.
- Item A, number 2: Average heat rate, both monthly and 12-month average.
- Item A, number 3: Equivalent forced-outage factor (see below), both monthly and 12-month average.
- Item A, number 5: Total fuel costs per month.
- Item A, number 6: the fuel cost per kWh per month.

The confidential PSA workpapers describes the EFOF as the fraction of a given period in which a generating unit is not available due to forced outages and forced deratings.[58] In addition, the response to Staff data request 8.5 states the following with regard to the EFOF:

> The APS budget simulates unscheduled outages based on planned effective forced outage factors (EFOF) for all resources. The production cost model used to create the budget ensures that simulated unscheduled outages, in aggregate, tie to the effective forced outage factors annually for each resource. Therefore, from a budget perspective, unscheduled outages are randomly distributed across the year which can result in timing and duration variances from month to month. Due to the use of multiple iterations under random draws of forced outages, resultant EFOFs from the model closely approximate the planned effective forced outage factors, on a monthly basis.

The exhibit below summarizes the monthly amounts for the items listed above (including EFOFs) for Cholla during 2019:

[57] See Staff data request 1.138, confidential attachment APS21FA00004, page 7.

[58] See the confidential PSA workpapers on the "Gen Details" tab that were provided in response to Staff data request 1.95.

Exhibit 4-34
Summary of Generation, Cost, Heat Rate and EFOF at Cholla During January through December 2019

Plant	Accredited Capability (MW)	Capability (MW)	Net Generated (MWh)		Total Fuel Costs	Cost per kWh ¢/kWh)	Avg Realized Heat Rate (BTU/kWh)	EFOF
January 2019								
Cholla Unit 1	116	86,304	17,627	$	658,972	3.74	11,349	0.1
Cholla Unit 3	271	201,624	41,900	$	1,641,941	3.92	12,173	19.4
February 2019								
Cholla Unit 1	116	77,952	(523)	$	166,821	N/A	-	0.0
Cholla Unit 3	271	182,112	76,632	$	2,344,360	3.06	11,079	22.7
March 2019								
Cholla Unit 1	116	86,304	(284)	$	182,105	N/A	(56)	0.0
Cholla Unit 3	271	201,624	96,491	$	3,018,347	3.13	11,311	17.9
April 2019								
Cholla Unit 1	116	83,520	(166)	$	192,738	N/A	-	0.0
Cholla Unit 3	271	195,120	99,923	$	3,116,233	3.12	11,517	0.0
May 2019								
Cholla Unit 1	116	86,304	2,459	$	369,064	15.01	25,359	0.6
Cholla Unit 3	271	201,624	42,098	$	1,753,256	4.16	12,535	2.9
June 2019								
Cholla Unit 1	116	83,520	27,192	$	929,873	3.42	12,090	1.1
Cholla Unit 3	271	195,120	66,843	$	2,261,762	3.38	11,938	0.0
July 2019								
Cholla Unit 1	116	86,304	44,973	$	1,272,172	2.83	10,593	0.0
Cholla Unit 3	271	201,624	121,152	$	3,557,022	2.94	11,311	0.1
August 2019								
Cholla Unit 1	116	86,304	43,281	$	1,297,634	3.00	11,143	3.9
Cholla Unit 3	271	201,624	114,957	$	3,427,229	2.98	11,284	0.0
September 2019								
Cholla Unit 1	116	83,520	34,593	$	1,061,187	3.07	11,030	0.0
Cholla Unit 3	271	195,120	70,738	$	2,292,159	3.24	11,439	1.6
October 2019								
Cholla Unit 1	116	86,304	32,597	$	1,036,510	3.18	11,454	10.7
Cholla Unit 3	271	201,624	44,126	$	1,685,367	3.82	12,041	8.7
November 2019								
Cholla Unit 1	116	83,520	45,597	$	1,330,360	2.92	10,849	1.7
Cholla Unit 3	271	195,120	118,289	$	3,466,842	2.93	11,062	0.2
December 2019								
Cholla Unit 1	116	86,304	43,716	$	1,298,212	2.97	10,712	2.7
Cholla Unit 3	271	201,624	113,820	$	3,479,055	3.06	11,134	0.0
Source: Staff Data Request 1.95 from the Generations (2) tab of the Confidential PSA Workpapers								

During a Microsoft Teams meeting with APS on October 29, 2021, the Company stated that the EFOFs listed in the confidential PSA workpapers (and in the above exhibit) are percentage figures. As shown in the above exhibit, the highest EFOFs were in January, February and March 2019 for Cholla Unit 3 at 19.4 percent, 22.7 percent and 17.9 percent, respectively. These high EFOFs correspond with the unplanned outages at Cholla Unit 3 during January through March 2019 as discussed above and shown in Exhibit 4-33.

The unplanned outages that occurred at Cholla during 2020 and January 2021 are summarized in the exhibit below:

Exhibit 4-35
Summary of Unplanned Outages at Cholla from January 2020 through January 2021

Line No.	Plant and Unit	Outage Start: Date / Time		Outage End: Date / Time		Outage Type	Description*	Hours
		January 2020						
1	Cholla Unit 1	04-Jan-20	14:51	04-Jan-20	16:36	U1	Unplanned	1.75
2	Cholla Unit 3	No Outages						
		February 2020						
3	Cholla Unit 1	05-Feb-20	09:44	07-Feb-20	17:46	U1	Unplanned	56.03
	Cholla Unit 1	29-Feb-20	00:48	01-Mar-20	00:00	U1	Unplanned	23.20
		March 2020						
4	Cholla Unit 1	01-Mar-20	00:00	02-Mar-20	16:30	U1	Unplanned	40.50
5	Cholla Unit 3	24-Mar-20	08:01	24-Mar-20	09:00	U1	Unplanned	0.98
6	Cholla Unit 3	24-Mar-20	09:00	25-Mar-20	18:41	U1	Unplanned	33.68
		April 2020						
7	Cholla Unit 1	No Outages						
8	Cholla Unit 3	No Outages						
		May 2020						
9	Cholla Unit 1	16-May-20	00:01	16-May-20	16:34	U1	Unplanned	16.55
		June 2020						
10	Cholla Unit 1	No Outages						
11	Cholla Unit 3	No Outages						
		July 2020						
12	Cholla Unit 1	No Outages						
13	Cholla Unit 3	No Outages						
		August 2020						
14	Cholla Unit 1	No Outages						
15	Cholla Unit 3	No Outages						
		September 2020						
16	Cholla Unit 1	No Outages						
17	Cholla Unit 3	No Outages						
		October 2020						
18	Cholla Unit 3	No Outages						
		November 2020						
19	Cholla Unit 3	No Outages						
		December 2020						
20	Cholla Unit 1	No Outages						
21	Cholla Unit 3	16-Dec-20	14:15	16-Dec-20	16:12	U1	Unplanned	1.95
22	Cholla Unit 3	16-Dec-20	16:29	16-Dec-20	18:52	U1	Unplanned	2.38
		January 2021						
23	Cholla Unit 1	No Outages						
24	Cholla Unit 3	17-Jan-21	13:26	25-Jan-21	03:15	U1	Unplanned	181.82
25	Cholla Unit 3	27-Jan-21	07:35	27-Jan-21	12:07	U1	Unplanned	4.53
26	Total Hours of Unplanned Outages as Cholla in 2020 and January 2021							363.37

Source: Staff Data Request 1.95 from the Outages tab of the Confidential PSA Workpapers

* Outage descriptions conform to the official NERC/GADS outage descriptions. All outages less than 1 hour have been excluded

As shown in the above exhibit, there were unplanned outages at Cholla totaling 363.37 hours during 2020 and January 2021. The most significant unplanned outages were at Unit 1 in February and March (56.03 hours and 40.5 hours, respectively) and Unit 3 in March 2020 and January 2021 (33.68 hours and 181.82 hours, respectively) with zero unplanned outages in April and from June through November. The remaining unplanned outages at Cholla Units 1 and 3 in 2020 and January 2021 were of a relatively short duration. Similar to 2019, there were also planned outages and maintenance performed at Cholla during 2020 as well, although the above exhibit reflects only the unplanned outages.

The exhibit below summarizes the monthly amounts for the generation, cost, heat rate and EFOFs at Cholla during 2020 and January 2021:

Exhibit 4-36
Summary of Generation, Cost, Heat Rate and EFOF at Cholla During January through December 2020 and January 2021

Plant	Accredited Capability (MW)	Capability (MW)	Net Generated (MWh)		Total Fuel Costs	Cost per kWh ¢/kWh)	Avg Realized Heat Rate (BTU/kWh)	EFOF
January 2020								
Cholla Unit 1	116	86,304	34,687	$	1,181,464	3.41	12,703	10.6
Cholla Unit 3	271	201,624	92,637	$	2,945,402	3.18	11,952	1.3
February 2020								
Cholla Unit 1	116	80,736	11,295	$	472,561	4.18	11,772	12.9
Cholla Unit 3	271	201,624	82,998	$	2,786,446	3.36	12,140	6.5
March 2020								
Cholla Unit 1	116	86,304	33,182	$	1,156,061	3.48	12,617	5.4
Cholla Unit 3	271	201,624	96,491	$	3,018,347	3.13	11,311	17.9
April 2020								
Cholla Unit 1	116	83,520	11,286	$	535,475	4.74	14,005	0.0
Cholla Unit 3	271	195,120	65,560	$	2,249,228	3.43	12,030	0.0
May 2020								
Cholla Unit 1	116	86,304	34,508	$	1,112,518	3.22	11,462	2.4
Cholla Unit 3	271	201,624	84,248	$	2,714,564	3.22	11,449	1.4
June 2020								
Cholla Unit 1	116	83,520	47,420	$	1,407,209	2.97	11,281	0.0
Cholla Unit 3	271	195,120	109,441	$	3,208,516	2.93	11,104	0.0
July 2020								
Cholla Unit 1	116	86,304	51,693	$	1,422,324	2.75	10,385	0.0
Cholla Unit 3	271	201,624	124,445	$	3,623,693	2.91	11,103	0.3
August 2020								
Cholla Unit 1	116	86,304	63,424	$	1,668,967	2.63	10,522	1.4
Cholla Unit 3	271	201,624	153,264	$	4,049,416	2.64	10,616	0.0
September 2020								
Cholla Unit 1	116	83,520	50,855	$	1,351,129	2.66	11,053	0.0
Cholla Unit 3	271	195,120	125,043	$	3,295,974	2.64	11,023	0.0
October 2020								
Cholla Unit 1	116	86,304	35,994	$	1,074,937	2.99	10,377	1.7
Cholla Unit 3	271	201,624	112,451	$	3,350,092	2.98	11,128	0.0
November 2020								
Cholla Unit 1	116	83,520	20,065	$	802,945	4.00	13,050	0.3
Cholla Unit 3	271	195,120	61,177	$	2,094,156	3.42	11,509	0.0
December 2020								
Cholla Unit 1	116	86,304	4,473	$	462,884	10.35	18,834	0.0
Cholla Unit 3	271	201,624	16,639	$	1,218,902	7.33	10,537	3.2
January 2021								
Cholla Unit 1	116	86,304	28,658	$	689,798	2.41	9,827	0.0
Cholla Unit 3	271	201,624	36,762	$	938,346	2.55	8,554	27.9
Source: Staff Data Request 1.95 from the Generations (2) tab of the Confidential PSA Workpapers								

As shown in the above exhibit, the highest EFOFs were in February and March 2020 for Cholla Units 1 and 3 at 12.9 percent and 17.9 percent, respectively, and at 27.9 percent in January 2021. These higher EFOFs correspond with the unplanned outages at Cholla Units 1 and 3 during February and March 2020 and January 2021 as discussed above and shown in Exhibit 4-22.

<u>Four Corners Plant</u>

For the Four Corners plant, we performed a similar analysis as that discussed above with regard to Cholla. The exhibit below shows the unplanned outage costs that were included in the PSA for Four Corners during each month of the review period:

Exhibit 4-37
Summary of Unplanned Outage Costs at Four Corners from January 2019 through January 2021 – Amounts in $000's

[redacted]

Similar to Cholla, as shown in the exhibit above, the unplanned outage costs for Four Corners are shown as gross replacement cost less avoided costs resulting in actual net replacement cost. [redacted]

With regard to how Four Corners replacement power costs are reflected in the PSA, the Company provided the following explanation in its response to Staff data request 9.2:

> The amount of Four Corners outage costs included in the PSA consists of the Actual Net Replacement Cost, offset by the Normalized Replacement Cost. Since all units have some level of unplanned (forced) outages, the expected outage levels are included in the APS base fuel rate by applying an equivalent forced outage rate (EFOR) in the modeled base fuel forecast.
>
> Every year, the EFOR and prices in the forecasted fuel and purchased power costs are adjusted based on latest estimates. The differences these changes cause in the forecast end up being reflected in the forward component rate of the PSA. The level of net replacement costs in our base fuel rate is referred to as the "Normalized Net Replacement Cost." Since the PSA is designed to recover costs above or below the base fuel rate, the PSA impact is the difference between Actual and Normalized.
>
> The Normalized outage level is driven by the EFOR, set by the historical unit performance and expected improvements based on maintenance performed in the overhaul cycle. In 2020 and 2019, EFOR was 19.8% and 15.3%, respectively. This is substantial improvement from the previous two years, which saw an EFOR of 27.1% in 2018 and 32.0% in 2017.

Based on the passage above, in its response to Staff data request 9.2, APS provided a schedule showing the calculation of the Four Corners unplanned outage costs that flowed through the PSA in 2019 and 2020, which is replicated in the following exhibit:

Exhibit 4-38
Four Corners Unplanned Outage Costs Included in the PSA for 2019 and 2020 – Amounts in $000's

[redacted]

The amounts shown on lines 1-9 in the exhibit above match the total 2019 and 2020 gross replacement costs, avoided costs and actual net replacement costs shown on Exhibit 4-37. With regard to the normalized net replacement costs (lines 10-18), the Company stated in a footnote to Attachment ExcelAPS21FA00331 that the normalized net replacement cost is determined from the normalized replacement energy at actual market fuel and purchased power prices. The amounts shown for the actual greater/(less) than normalized net replacements costs (lines 19-21) reflect the differences between the actual net replacement costs (lines 7-9) and the normalized net replacement costs (lines 16-18). The amounts on lines 19-21 are then multiplied by the retail allocation factors[59] shown on line 22 for 2019 and 2019 in order to determine that retail jurisdictional share of the net replacement costs (lines 23-25) that flowed into the PSA in 2019 and 2020. As shown on line 23 in the above exhibit, for Four Corners Unit 4, the net replacement costs deferred to the PSA was a credit amount of [redacted]

The actual and normalized net replacement costs for Four Corners discussed above and shown in Exhibit 4-38 are total year-end amounts for 2019 and 2020. We reviewed the Company's confidential PSA workpapers, which had similar calculations for each month of the review period on the tab titled "Outage Costs" and we verified that the calculations shown in Exhibit 4-38 were included in the confidential monthly PSA workpapers. No exceptions were noted.

On the Outages tab in the Company's confidential monthly PSA filing workpapers, which reflects monthly information, including, but not limited to, event type, start date and time, end date and time, and a description, reflected the following unplanned outage information for Four Corners in 2019:

[59] The retail jurisdictional allocation factor is calculated from the Company's public PSA filings for December 2019 and December 2020. Specifically, PSA retail energy sales are divided by total native load energy sales on Schedule 3 from the public PSA filings, which APS provided in its response to Staff data request 1.95.

Exhibit 4-39
Summary of Unplanned Outages at Four Corners from January through December 2019

Line No.	Plant and Unit	Outage Start: Date / Time		Outage End: Date / Time		Outage Type	Description*	Unit 4	Unit 5	Total Hours
		January 2019								
1	Four Corners Unit 4	07-Jan-19	00:34	07-Jan-19	23:30	U1	Unplanned	22.93		22.93
2	Four Corners Unit 4	08-Jan-19	01:18	08-Jan-19	04:12	U1	Unplanned	2.90		2.90
3	Four Corners Unit 4	10-Jan-19	11:21	11-Jan-19	02:33	U1	Unplanned	15.20		15.20
4	Four Corners Unit 5	07-Jan-19	02:11	09-Jan-19	08:49	U1	Unplanned		54.63	54.63
		February 2019								
5	Four Corners Unit 4	No Outages								
6	Four Corners Unit 5	28-Feb-19	16:28	01-Mar-19	00:00	U1	Unplanned		7.53	7.53
		March 2019								
7	Four Corners Unit 4	No Unplanned								
8	Four Corners Unit 5	No Unplanned								
		April 2019								
9	Four Corners Unit 4	02-Apr-19	10:09	02-Apr-19	21:36	U1	Unplanned	11.45		11.45
10	Four Corners Unit 4	03-Apr-19	04:08	03-Apr-19	10:24	U1	Unplanned	6.27		6.27
		May 2019								
11	Four Corners Unit 4	No Outages								
12	Four Corners Unit 5	21-May-19	23:04	31-May-19	11:04	U1	Unplanned		228.00	228.00
		June 2019								
13	Four Corners Unit 4	29-Jun-19	11:05	01-Jul-19	00:00	U1	Unplanned	65.42		65.42
14	Four Corners Unit 5	02-Jun-19	23:14	03-Jun-19	08:26	U1	Unplanned		65.42	65.42
		July 2019								
15	Four Corners Unit 4	01-Jul-19	00:00	01-Jul-19	23:29	U1	Unplanned	23.48		23.48
16	Four Corners Unit 5	06-Jul-19	20:50	07-Jul-19	21:50	U1	Unplanned		25.00	25.00
17	Four Corners Unit 5	07-Jul-19	23:53	09-Jul-19	05:09	U1	Unplanned		29.27	29.27
		August 2019								
18	Four Corners Unit 4	No Outages								
19	Four Corners Unit 5	No Outages								
		September 2019								
20	Four Corners Unit 4	No Outages								
21	Four Corners Unit 5	No Outages								
		October 2019								
22	Four Corners Unit 4	No Outages								
23	Four Corners Unit 5	24-Oct-19	22:01	26-Oct-19	02:40	U1	Unplanned		28.65	28.65
		November 2019								
24	Four Corners Unit 4	No Outages								
25	Four Corners Unit 5	14-Nov-19	00:53	16-Nov-19	21:28	U1	Unplanned		68.58	68.58
26	Four Corners Unit 5	18-Nov-19	20:00	21-Nov-19	05:00	U1	Unplanned		57.00	57.00
27	Four Corners Unit 5	29-Nov-19	10:20	01-Dec-19	00:00	U1	Unplanned		37.67	37.67
		December 2019								
28	Four Corners Unit 4	19-Dec-19	15:03	20-Dec-19	16:35	U1	Unplanned	25.53		25.53
29	Four Corners Unit 4	20-Dec-19	16:35	21-Dec-19	17:09	U1	Unplanned	24.57		24.57
30	Four Corners Unit 4	22-Dec-19	08:30	22-Dec-19	20:34	U1	Unplanned	12.07		12.07
31	Four Corners Unit 5	01-Dec-19	00:00	07-Dec-19	11:42	U1	Unplanned		155.70	155.70
32	Four Corners Unit 5	09-Dec-19	22:02	11-Dec-19	08:58	U1	Unplanned		34.93	34.93
33	Four Corners Unit 5	20-Dec-19	22:06	27-Dec-19	09:30	U1	Unplanned		155.40	155.40
34	Total Hours of Unplanned Outages as Four Corners in 2019							209.82	947.78	1,157.60

Source: Staff Data Request 1.95 from the Outages tab of the Confidential PSA Workpapers

* Outage descriptions conform to the official NERC/GADS outage descriptions. All outages less than 1 hour have been excluded.

As shown in the above exhibit, there were unplanned outages at Four Corners totaling 1,157.60 hours (209.82 – Unit 4 + 947.78 – Unit 5) during 2019. The unplanned outages at Four Corners Unit 4 occurred in January, April, June, July, and December. Unplanned outages occurred at Unit 5 in January, February, May, June, July, October, November, and December. Four Corners had zero unplanned outages in August and September. It should be noted that there were also planned outages and maintenance performed at Four Corners during 2019 as well, although the above exhibit reflects only the unplanned outages.

The exhibit below summarizes the monthly amounts for the generation, cost, heat rate and EFOFs at Four Corners during 2019:

Exhibit 4-40
Summary of Generation, Cost, Heat Rate and EFOF at Four Corners During January through December 2019

Plant	Accredited Capability (MW)	Capability (MW)	Net Generated (MWh)		Total Fuel Costs	Cost per kWh ¢/kWh)	Realized Heat Rate (BTU/kWh)	EFOF
January 2019								
Four Corners Unit 4	485	360,914	283,575	$	8,395,463	2.96	8,700	6.2
Four Corners Unit 5	485	360,914	244,596	$	7,254,893	2.97	8,647	20.5
February 2019								
Four Corners Unit 4	485	325,987	283,126	$	8,242,364	2.91	8,548	3.0
Four Corners Unit 5	485	325,987	248,167	$	7,260,401	2.93	8,509	18.6
March 2019								
Four Corners Unit 4	485	360,914	83,966	$	2,933,179	3.49	10,479	9.2
Four Corners Unit 5	485	360,914	75,817	$	2,743,962	3.62	10,633	17.4
April 2019								
Four Corners Unit 4	485	349,272	190,880	$	5,669,078	2.97	8,883	6.5
Four Corners Unit 5	485	349,272	264,681	$	7,860,379	2.97	8,787	2.8
May 2019								
Four Corners Unit 4	485	360,914	244,741	$	6,697,818	2.74	10,015	8.2
Four Corners Unit 5	485	360,914	148,544	$	4,134,708	2.78	10,133	33.4
June 2019								
Four Corners Unit 4	485	349,272	269,219	$	7,673,750	2.85	8,506	6.5
Four Corners Unit 5	485	349,272	273,670	$	7,883,963	2.88	8,611	2.1
July 2019								
Four Corners Unit 4	485	360,914	311,465	$	9,359,163	3.00	9,597	4.4
Four Corners Unit 5	485	360,914	291,332	$	8,833,661	3.03	9,618	9.2
August 2019								
Four Corners Unit 4	485	360,914	313,184	$	9,469,432	3.02	10,056	2.4
Four Corners Unit 5	485	360,914	292,354	$	8,986,582	3.07	10,162	9.0
September 2019								
Four Corners Unit 4	485	349,272	272,592	$	8,181,025	3.00	10,054	10.9
Four Corners Unit 5	485	349,272	237,594	$	7,552,546	3.18	10,102	21.0
October 2019								
Four Corners Unit 4	485	360,914	282,583	$	8,784,111	3.11	10,290	13.1
Four Corners Unit 5	485	360,914	128,566	$	4,176,302	3.25	10,490	12.7
November 2019								
Four Corners Unit 4	485	349,272	263,199	$	8,152,930	3.10	10,267	14.5
Four Corners Unit 5	485	349,272	172,994	$	5,561,127	3.21	10,467	39.4
December 2019								
Four Corners Unit 4	485	360,914	236,903	$	10,206,673	4.31	10,812	27.7
Four Corners Unit 5	485	360,914	139,791	$	7,103,444	5.08	10,717	54.2
Source: Staff Data Request 1.95 from the Generations (2) tab of the Confidential PSA Workpapers								

As shown in the above exhibit, the highest EFOFs were in January, May, November and December 2019 for Four Corners Unit 5 at 20.5 percent, 33.4 percent, 39.4 percent and 54.2 percent, respectively. These high EFOFs correspond with the unplanned outages at Four Corners Unit 5 during the referenced months as discussed above and shown in Exhibit 4-39.

The unplanned outages that occurred at Four Corners during 2020 and January 2021 are summarized in the exhibit below:

Exhibit 4-41
Summary of Unplanned Outages at Four Corners from January 2020 through January 2021

Line No.	Plant and Unit	Outage Start: Date	Time	Outage End: Date	Time	Outage Type	Description*	Unit 4	Unit 5	Total Hours
		January 2020								
1	Four Corners Unit 4	No Unplanned								
2	Four Corners Unit 5	No Outages								
		February 2020								
3	Four Corners Unit 4	04-Feb-20	22:00	07-Feb-20	09:43	U3	Unplanned	59.72		59.72
		March 2020								
4	Four Corners Unit 4	No Outages								
5	Four Corners Unit 5	No Unplanned								
		April 2020								
6	Four Corners Unit 4	No Outages								
7	Four Corners Unit 5	No Unplanned								
		May 2020								
8	Four Corners Unit 4	No Unplanned								
9	Four Corners Unit 5	08-May-20	06:17	16-May-20	11:02	U1	Unplanned		196.75	196.75
10	Four Corners Unit 5	16-May-20	15:45	17-May-20	01:00	U1	Unplanned		9.25	9.25
		June 2020								
11	Four Corners Unit 4	01-Jun-20	23:16	07-Jun-20	10:00	U1	Unplanned	130.73		130.73
12	Four Corners Unit 4	08-Jun-20	19:08	20-Jun-20	06:09	U1	Unplanned	10.07		10.07
13	Four Corners Unit 5	No Outages								
		July 2020								
14	Four Corners Unit 4	25-Jul-20	00:35	25-Jul-20	18:19	U1	Unplanned	17.73		17.73
15	Four Corners Unit 4	26-Jul-20	11:27	30-Jul-20	19:38	U1	Unplanned	104.18		104.18
16	Four Corners Unit 5	28-Jul-20	09:28	29-Jul-20	00:05	U1	Unplanned		14.62	14.62
		August 2020								
17	Four Corners Unit 4	No Outages								
18	Four Corners Unit 5	02-Aug-20	23:51	04-Aug-20	00:14	U1	Unplanned		24.38	24.38
19	Four Corners Unit 5	07-Aug-20	09:40	14-Aug-20	04:03	U1	Unplanned		162.38	162.38
		September 2020								
20	Four Corners Unit 4	No Outages								
21	Four Corners Unit 5	No Outages								
		October 2020								
22	Four Corners Unit 4	No Unplanned								
23	Four Corners Unit 5	23-Oct-20	11:44	23-Oct-20	19:15	U1	Unplanned		7.52	7.52
24	Four Corners Unit 5	23-Oct-20	11:44	23-Oct-20	19:15	U1	Unplanned		7.52	7.52
		November 2020								
25	Four Corners Unit 4	04-Nov-20	06:45	09-Nov-20	21:03	U1	Unplanned	134.30		134.3
26	Four Corners Unit 4	13-Nov-20	08:00	01-Dec-20	00:00	U1	Unplanned	424.00		424
27	Four Corners Unit 5	25-Nov-20	08:00	01-Dec-20	00:00	U1	Unplanned		136.00	136
		December 2020								
28	Four Corners Unit 4	01-Dec-20	00:00	10-Dec-20	09:54	U1	Unplanned	225.90		225.9
29	Four Corners Unit 4	16-Dec-20	13:29	17-Dec-20	04:31	U1	Unplanned	15.03		15.03
30	Four Corners Unit 5	01-Dec-20	00:00	04-Dec-20	00:15	U1	Unplanned		72.25	72.25
31	Four Corners Unit 5	28-Dec-20	20:18	01-Jan-21	00:00	U2	Unplanned		75.70	75.7
		January 2021								
32	Four Corners Unit 4	No Outages								
33	Four Corners Unit 5	01-Jan-21	00:00	03-Jan-21	17:11	U2	Unplanned		65.18	65.18
34	Four Corners Unit 5	27-Jan-21	00:27	27-Jan-21	16:41	U1	Unplanned		16.23	16.23
35	Total Hours of Unplanned Outages as Four Corners in 2020 and January 2021							1,121.66	787.78	1,909.44

Source: Staff Data Request 1.95 from the Outages tab of the Confidential PSA Workpapers

As shown in the above exhibit, there were unplanned at Four Corners outages totaling 1,909.44 hours (1,121.66 – Unit 4 + 787.78 – Unit 5) during 2020 and January 2021. There were unplanned outages at Four Corners Unit 4 in February, June, July, November and December. For Unit 5, there were unplanned outages in May, August, November and December 2020 as well as in January 2021. There were zero unplanned outages at Units 4 and 5 in March, April and September 2020. The remaining unplanned outages at Four Corners Units 4 and 5 in 2020 were of a relatively short duration. Similar to 2019, there were also planned outages and maintenance performed at Four Corners during 2020 as well, although the above exhibit reflects only the unplanned outages.

The exhibit below summarizes the monthly amounts for the generation, cost, heat rate and EFOFs at Four Corners during 2020 and January 2021:

Exhibit 4-42
Summary of Generation, Cost, Heat Rate and EFOF at Four Corners During January through December 2020 and January 2021

Plant	Accredited Capability (MW)	Capability (MW)	Net Generated (MWh)	Total Fuel Costs	Cost per kWh ¢/kWh)	Realized Heat Rate (BTU/kWh)	EFOF
January 2020							
Four Corners Unit 4	485	360,914	176,022	$ 6,864,382	3.90	10,345	9.6
Four Corners Unit 5	485	360,914	286,950	$ 10,445,680	3.64	10,402	9.8
February 2020							
Four Corners Unit 4	485	337,630	240,782	$ 8,350,648	3.47	10,398	18.6
Four Corners Unit 5	485	337,630	124,982	$ 4,793,022	3.83	10,216	5.5
March 2020							
Four Corners Unit 4	485	360,914	274,239	$ 8,367,341	3.05	10,730	17.4
Four Corners Unit 5	485	360,914	-	$ (222,607)	0.00	-	0.0
April 2020							
Four Corners Unit 4	485	349,272	263,003	$ 7,821,875	2.97	10,805	16.2
Four Corners Unit 5	485	349,272	-	$ (473,174)	0.00	-	0.0
May 2020							
Four Corners Unit 4	485	360,914	59,449	$ 2,437,384	4.10	10,815	3.6
Four Corners Unit 5	485	360,914	167,550	$ 5,798,871	3.46	10,779	31.9
June 2020							
Four Corners Unit 4	485	349,272	108,513	$ 3,410,808	3.14	10,355	57.3
Four Corners Unit 5	485	349,272	299,430	$ 8,267,410	2.76	9,803	0.3
July 2020							
Four Corners Unit 4	485	360,914	261,712	$ 8,527,210	3.26	10,269	17.8
Four Corners Unit 5	485	360,914	310,461	$ 10,826,392	3.49	10,250	2.3
August 2020							
Four Corners Unit 4	485	360,914	332,702	$ 9,677,458	2.91	10,192	0.4
Four Corners Unit 5	485	360,914	232,061	$ 6,839,644	2.95	10,178	28.7
September 2020							
Four Corners Unit 4	485	349,272	325,884	$ 8,914,450	2.74	10,048	0.0
Four Corners Unit 5	485	349,272	322,899	$ 9,152,958	2.83	9,931	0.0
October 2020							
Four Corners Unit 4	485	360,914	235,432	$ 6,543,290	2.78	9,906	8.9
Four Corners Unit 5	485	360,914	138,804	$ 3,883,932	2.80	10,160	2.2
November 2020							
Four Corners Unit 4	485	349,272	63,100	$ 2,287,203	3.62	10,710	77.5
Four Corners Unit 5	485	349,272	135,453	$ 4,460,257	3.29	10,610	19.3
December 2020							
Four Corners Unit 4	485	360,914	211,040	$ 6,606,016	3.13	9,989	32.7
Four Corners Unit 5	485	360,914	248,943	$ 7,664,408	3.08	9,897	19.9
January 2021							
Four Corners Unit 4	485	360,914	292,976	$ 8,983,022	3.07	9,931	5.9
Four Corners Unit 5	485	360,914	250,176	$ 7,787,654	3.11	9,910	20.2

Source: Staff Data Request 1.95 from the Generations (2) tab of the Confidential PSA Workpapers

As shown in the above exhibit, the highest EFOFs were in February, June, July, November and December 2020 for Four Corners Unit 4 at 18.6 percent, 57.3 percent, 17.8 percent, 77.5 percent and 32.7 percent, respectively. For Four Corners Unit 5, the highest EFOFs were in May, August, November and December 2020 at 31.9 percent, 28.7 percent, 19.3 percent, and 19.9 percent, respectively, and at 20.2 percent in January 2021. These higher EFOFs correspond with the unplanned outages at Four Corners Units 4 and 5 during the referenced months as discussed above and shown in Exhibit 4-41.

We calculated the overall EFOFs for Four Corners for calendar years 2019 and 2020 and compared them to EFOF benchmarks taken from the GADS database as shown in the exhibit below:

Exhibit 4-43
Comparison of Four Corners Units 4 and 5 EFOFs to Industry Benchmarks for 2019 and 2020

Line	Description	2019	2020	Total	Reference
1	Industry Benchmark Equivalent Forced Outage Factor	6.6%	11.7%		GADS Database
		Unit 4	Unit 5		
2	Total Hours of Unplanned Outages at Four Corners in 2019	209.82	947.78	1157.60	Exhibit 4-39
3	Annual Hours (24 x 365)	8,760	8,760		
4	Four Corners 2019 Equivalent Forced Outage Factors	2.4%	10.8%		L2 / L3
		Unit 4	Unit 5		
5	Total Hours of Unplanned Outages at Four Corners in 2020	1121.66	706.37	1828.03	Exhibit 4-41
6	Annual Hours (24 x 365)	8,760	8,760		
7	Four Corners 2020 Equivalent Forced Outage Factors	12.8%	8.1%		L5 / L6

As shown in the above exhibit, the EFOF benchmarks from the GADS database were 6.6 percent and 11.7 percent for 2019 and 2020, respectively. In addition, the annual EFOFs for Four Corners Unit 4 were 2.4 percent and 10.8 percent for 2019 and 2020, respectively. The annual EFOFs for Four Corners Unit 5 were 12.8 percent and 8.1 percent for 2019 and 2020, respectively. Despite the large number of unplanned outages at Four Corners Units 4 and 5 during 2019 and 2020, the EFOFs for Units 4 and 5 in both years were not substantially different from industry experience.

Palo Verde

The Palo Verde power plant, of which APS has a 29.1 percent ownership stake, is comprised of Units 1-3 and is powered by nuclear steam with each unit having a capacity of 382 MW. Unlike Cholla and Four Corners, Palo Verde only had three unplanned outages during the review period, which are summarized in the table below:

Exhibit 4-44
Summary of Unplanned Outages at Palo Verde from January 2020 through January 2021

Plant and Unit	Outage Start: Date	Time	Outage End: Date	Time	Outage Type	Description	Hours
Palo Verde Unit 2	16-Aug-19	08:20	20-Aug-19	02:06	U1	Unplanned	89.77
Palo Verde Unit 3	18-Nov-19	11:30	21-Nov-19	01:07	U1	Unplanned	61.62
Palo Verde Unit 2	03-Mar-20	20:50	07-Mar-20	22:40	U2	Unplanned	97.83
Source: Staff Data Request 1.95 from the Outages tab of the Confidential PSA Workpapers							

As shown in the above exhibit, there were two unplanned outages at Palo Verde in 2019 (Unit 2 in August and Unit 3 in November) and one unplanned outage at Unit 2 in March 2020. The EFOFs for these unplanned outages were 14.5 percent, 8.6 percent and 16 percent, respectively.[60] The actual net replacement costs (gross replacement cost – avoided costs) for the two unplanned outages in 2019 were $386,000 and $38,000, respectively, while the actual net replacement cost for the March 2020 unplanned outage was $322,000.[61] The fact that there were only three unplanned outages during the review period indicates that the Palo Verde units are well maintained and operated effectively as intended during the review period.

<u>Gas Fired, Combined Cycle and Combustion Turbine Plants</u>

We also reviewed the unplanned outages associated with APS's gas/oil fired, combined cycle and combustion turbine generating units during the review period. Upon reviewing the monthly unplanned outages from these sources of generation (from the confidential PSA workpapers), with the exception of August 2019, we noted numerous instances during the review period in which certain generating facilities encountered unplanned outages that lasted a month or longer[62] during 2019, 2020 and January 2021. These generating facilities are summarized in the exhibit below:

Exhibit 4-45
Summary of Generating Units that had Extended Unplanned Outages from January 2019 through January 2021

Generating Plant and Unit				
OCOTILLO CT1	REDHAWK ST1	SAGUARO CT2	WEST PHOENIX CC1	YUCCA CT2
OCOTILLO GT4	REDHAWK CT1A	SAGUARO CT3	WEST PHOENIX CC2	YUCCA CT3
OCOTILLO GT7	REDHAWK CT1B		WEST PHOENIX CC3	YUCCA CT4
			WEST PHOENIX CC4	
			WEST PHOENIX CT1	
			WEST PHOENIX CT2	
			WEST PHOENIX CT5A	
			WEST PHOENIX ST5	
Source: Staff Data Request 1.95 from the Outages tab				

[60] The EFOFs are from the confidential PSA workpapers provided in Staff data request 1.95 on the Generations (2) tab.

[61] The actual net replacement costs are from the confidential PSA workpapers provided in Staff data request 1.95 on the Outage Summary tab.

[62] Many of the Company's non-coal and non-nuclear generating facilities indicated unplanned outages lasting 720 hours (30 days) or 744 hours (31 days) (or longer) during the review period.

As shown in the above exhibit, the extended unplanned outages occurred at the various combustion turbine, combined cycle and gas-fired units at the Ocotillo, Redhawk, Saguaro, West Phoenix and Yucca generating facilities.

With regard to the Outage Type descriptions associated with these unplanned outages, we noted that the Company designated such outages as either "U1" or "SF". In its response to Staff data request 11.1, APS stated that it adheres to the required North American Electric Reliability Corporation – Generating Availability Data System ("NERC-GADS") Outage Event Reporting compliance and that the NERC-GADS event type code "U1" indicates a Forced Outage – Immediate whereas the event type code "SF" stands for Startup Failure.

As noted above, the response to Staff data request 1.44 lists the specific causes and circumstances related to the unplanned outages that occurred at the Company's generating units during the review period. We asked APS to explain why the unplanned outages listed at the generating units in the above exhibit were so frequent and of such long duration during the review period. In its initial responses to Staff data request 11.1 and Staff data request 11.2, the Company stated that it is gathering data specific to the extended unplanned outages during the review period and will provide more detailed information as it becomes available.

In terms of a general description of the unplanned outage duration, APS stated that there are commonalities between the lengthy unplanned outages. Specifically, when an outage is caused by equipment failure, the Company strives to make repairs on-site, but in circumstances in which extensive or specialized repairs are necessary, the damaged equipment is shipped to the manufacturer, which can delay the duration of the outage. APS stated that it takes steps not only to avoid unplanned outages, but to reduce their frequency and length such as through (1) regular planned maintenance, (2) major and minor overhauls, and (3) adherence to manufacturer recommendations.

Despite these efforts, APS acknowledged that unplanned outages do occur. As a result, the Company recognizes and budgets for a level of unplanned outages and associated energy replacement costs each year. As is standard in the utility industry, EFOFs are included in both APS base fuel rates as well as in the annual PSA budgets and are updated annually to tie to Generations' business plan in order to align with operational targets.[63] In addition, when unplanned outage occurs, APS relies on a combination of its own generation and market purchases to procure additional energy (as necessary) to provide power to its customers. According to the responses to Staff data request 11.1 and Staff data request 11.2, the Company's customers did not experience any electricity outages during the review period as a result of the extended unplanned outages.

In terms of the costs (including replacement costs) associated with the unplanned outages at the generating units listed in Exhibit 4-45, APS confirmed that combined cycle replacement costs (if any) are reflected in the confidential PSA workpapers provided in Staff data request 1.95. With regard to these combined cycle replacement costs, in its response to Staff data request 11.1, the Company stated:

> Please also note that the majority of the unplanned outages occurred in the winter months when APS's overall system load is low and availability of generation in the Western system is relatively high. In these months, replacement cost is

[63] See the response to Staff data request 11.1.

generally low absent an extreme weather event (of which there were none in 2019) and in many cases, market replacement power is unnecessary as APS can replace any needed energy with its own generation.

In addition, the Company does not calculate replacement power costs for CTs since the power that would have otherwise been generated from CT units is assumed to be replaced with power from another APS-owned CT generator at similar cost.

West Phoenix Combined Cycle Unit 4 Unplanned Outage

In some instances, some of these unplanned outages lasted for longer than a month. For example, as shown in the exhibit below, the West Phoenix Combined Cycle Unit 4 ("West Phoenix CC4"), a combined cycle generating unit encountered an unplanned outage that lasted from January 1, 2019 through May 26, 2019, or nearly five months.[64]

Exhibit 4-46
Unplanned Outages at West Phoenix CC4 from January through May 2019

Line No.	Plant and Unit	Outage Start: Date	Time	Outage End: Date	Time	Outage Type	Description	Hours
1	WEST PHOENIX CC4	01-Jan-19	00:00	01-Feb-19	00:00	U1	Unplanned	744.00
2	WEST PHOENIX CC4	01-Feb-19	00:00	01-Mar-19	00:00	U1	Unplanned	672.00
3	WEST PHOENIX CC4	01-Mar-19	00:00	01-Apr-19	00:00	U1	Unplanned	744.00
4	WEST PHOENIX CC4	01-Apr-19	00:00	01-May-19	00:00	U1	Unplanned	720.00
5	WEST PHOENIX CC4	01-May-19	00:00	26-May-19	10:31	U1	Unplanned	610.52
6							Total	3,490.52
Source: Staff Data Request 1.95 - Confidential PSA workpapers from the Outages tab								

As shown in the above exhibit, the unplanned outage at West Phoenix CC4 lasted for approximately 3,491 hours. As discussed previously, APS provided a confidential Event Report in its response to Staff data request 1.44, which lists the unplanned outages that occurred during the review period along with the associated reasons for such unplanned outages. As it relates to the five-month long unplanned outage at West Phoenix CC4, under the column heading "Cause Code Name", the Event Report states "Vibration of the turbine generator unit that cannot be attributed to a specific cause such as bearings or blades." Under the column heading "Event Description" it states "steamer tripped offline" unit needs to be off for troubleshooting." We asked APS a series of questions about this unplanned outage, including: (1) why it took five months to repair the tripped steamer, (2) how much it cost to repair the tripped steamer, (3) whether the costs to repair the tripped steamer were included in the PSA, and (4) whether any of the costs to repair the tripped steamer was covered by a manufacturer's warranty. With regard to why it took five months to repair the tripped steamer at West Phoenix CC4, in its response to Staff data request 11.3, the Company stated:

> This unplanned outage was a major outage that had a longer duration than a typical reliability maintenance outage, mainly due to the need for refurbishment of the rotor and the need to replace the L0 turbine blades, which was not evident until the unit tripped offline in December 2018. Refurbishment of the rotor was

[64] These unplanned outages are reflected in the monthly confidential PSA workpapers provided in response to Staff data request 1.95.

scheduled to be complete in eight weeks but because the turbine blades needed to be manufactured off-site, the outage duration was extended.

According to the response to Staff data request 11.1, there have been instances whereby outages are coded as unplanned in the system, but that these outages would have been more appropriately coded (at least partially) as a planned or maintenance outage. APS cited the unplanned outage at West Phoenix CCR as an example of this.[65] Specifically, the Company stated:

> West Phoenix Combined Cycle (CC) 4 had a planned major outage scheduled for Fall 2019; however, when the steam turbine tripped on vibrations in December of 2018 that outage was moved up so planned maintenance could be accomplished while the rotor was replaced. In addition to the rotor replacement, the L0 turbine blades were required to be replaced and had to be built. The entire outage was coded as Unplanned in accordance with NERC-GADS outage descriptions because the outage was unscheduled at the time it began.

The capitalized and O&M expense for repairing the equipment at West Phoenix CC4 was approximately $5.5 million. However, the Company stated that none of these costs were flowed through the PSA. In addition, none of the costs to repair the tripped steamer at West Phoenix CC4 were covered by the manufacturer's warranty.[66]

We calculated the overall EFOFs for West Phoenix CC Units 1-4 for calendar year 2019 and compared them to EFOF benchmarks taken from the GADS database as shown in the exhibit below:

Exhibit 4-47
Comparison of West Phoenix CC Units 1-4 EFOFs to Industry Benchmarks for 2019

Date	West Phoenix CC1	West Phoenix CC2	West Phoenix CC3	West Phoenix CC4	Combined Cycle EFOF Industry Benchmark*
January 2019	498.00		418.70	744.00	
February 2019	672.00			672.00	
March 2019	680.75			744.00	
April 2019				720.00	
May 2019				610.52	
June 2019					
July 2019		239.45			
August 2019					
September 2019					
October 2019					
November 2019					
December 2019					
Total 2019	1850.75	239.45	418.70	3490.52	
Annual Hours (24 x 365)	8,760	8,760	8,760	8,760	
West Phoenix CC Units - EFOFs	21.13%	2.73%	4.78%	39.85%	4.68%

Source: Staff Data Request 1.95
* Industry Benchmark from GADS Data

[65] In response to Staff data request 11.1, APS also cited West Phoenix CC3, which had a planned outage at the end of 2018 that needed to be extended because assembly of the turbine/rotor after overhaul took longer than expected. The extension was coded as an unplanned outage but should have been coded as an extended outage.
[66] See the response to Staff data request 11.3.

As shown in the above exhibit, the EFOF benchmark in 2019 for combined cycle units from the GADS database was 4.68 percent, which is generally in line with the EFOFs calculated for West Phoenix CC2 and CC3. However, the 2019 EFOFs for West Phoenix CC1 and CC4 were well above the industry benchmark at 21.13 percent and 39.85 percent, respectively. The unplanned outages for West Phoenix CC4 are the same as those discussed above pursuant to the tripped steamer. As noted above, the Company did not include any of the $5.5 million of capital and O&M costs to repair the tripped steamer at West Phoenix CC4 in the PSA, as those costs would not have qualified for PSA inclusion.

The replacement costs related to the West Phoenix CC4 outage, which flow through the PSA, are summarized in the exhibit below:

Exhibit 4-48
Summary of Actual Net Replacement Costs of Unplanned Outage at West Phoenix CC4

[redacted]

As shown in the above exhibit, [redacted]

In 2020 there was only one unplanned outage at West Phoenix CC4, which occurred in May and lasted 221.08 hours resulting in a EFOF of 2.52 percent (221.08 / 8,760), which is below the 2020 industry benchmark for combined cycle units of 4.84 percent (per GADS).

Conclusion

As discussed above, during the review period, there were a number of unplanned outages during the review period, which resulted in APS (and the co-owners) incurring substantial costs for replacement power, primarily at Four Corners. Despite the EFOFs from the unplanned outages at Four Corners Units 4 and 5 during 2019 and 2020, being relatively similar to industry benchmarks, a substantial amount of replacement cost relative to unplanned outages at Four Corners flowed through the PSA. We recommend that the Company review plant operations and its plans for scheduled maintenance to avoid having significant additional unplanned outages at the Four Corners plant during periods when the plant's capacity is needed to meet demand and/or when the cost of replacement power is high. APS should include in a footnote in its PSA filings, the amounts of replacement costs related to unplanned outages at nuclear, coal and combined cycle generating facilities, and to also include a description regarding the type and reason(s) for each extended unplanned outage.

Capacity Factors and Equivalent Availability Factors

The capacity factor is the measure of how often a generating unit runs for a specific period of time. The capacity factor is expressed as a percentage and is calculated by dividing the actual unit electricity output by the maximum possible output. This ratio indicates how fully a unit's capacity is being used. Capacity factors can vary considerably by plant and fuel type with nuclear energy typically having a higher capacity factor than non-nuclear generating units. An EAF represents the fraction of a given operating period in which a utility's generating units are available without any outages or equipment issues.

We requested that APS provide the operating availability and capacity factors of its non-nuclear generating units for each year 2010 through 2020 and January 2021. In its response to Staff data request 1.55, the Company provided the requested confidential information on an annual basis.[67] The capacity factors and EAFs for Cholla Units 1 and 3 for the period 2010 through 2020 are shown in the exhibit below:

Exhibit 4-49
Cholla Plant Capacity Factors and Equivalent Availability Factors for the Period 2010-2020

Generating Unit	Year	Period Hours	Net Max Cap (MW)	Net Generation (MWh)	Net Capacity Factor	Capacity Factor % Change	Equivalent Availability Factor	Equivalent Availability Factor % Change
Cholla Plant Unit 1	2010	8760	116.0	923,418	90.9%		94.3%	
Cholla Plant Unit 1	2011	8760	116.0	861,875	84.8%	-6.71%	88.7%	-5.94%
Cholla Plant Unit 1	2012	8784	116.0	830,109	81.5%	-3.89%	93.2%	5.07%
Cholla Plant Unit 1	2013	8760	116.0	822,820	81.0%	-0.61%	94.3%	1.18%
Cholla Plant Unit 1	2014	8760	116.0	787,284	77.5%	-4.32%	91.1%	-3.39%
Cholla Plant Unit 1	2015	8760	116.0	627,268	61.7%	-20.39%	93.0%	2.09%
Cholla Plant Unit 1	2016	8784	116.0	123,464	12.1%	-80.39%	78.4%	-15.70%
Cholla Plant Unit 1	2017	8760	116.0	398,758	39.4%	225.62%	93.4%	19.13%
Cholla Plant Unit 1	2018	8760	116.0	473,190	46.6%	18.27%	90.4%	-3.21%
Cholla Plant Unit 1	2019	8760	116.0	291,061	28.7%	-38.41%	70.6%	-21.90%
Cholla Plant Unit 1	2020	8784	116.0	398,879	39.1%	36.24%	89.7%	27.05%
Cholla Plant Unit 3	2010	8760	271.00	1,984,965	83.6%		92.3%	
Cholla Plant Unit 3	2011	8760	271.00	1,799,393	75.8%	-9.33%	86.7%	-6.07%
Cholla Plant Unit 3	2012	8784	271.00	1,638,310	68.8%	-9.23%	84.7%	-2.31%
Cholla Plant Unit 3	2013	8760	271.00	1,774,982	74.8%	8.72%	92.7%	9.45%
Cholla Plant Unit 3	2014	8760	271.00	1,578,410	66.6%	-10.96%	82.4%	-11.11%
Cholla Plant Unit 3	2015	8760	268.25	1,299,762	55.3%	-16.97%	86.9%	5.46%
Cholla Plant Unit 3	2016	8784	269.17	568,885	24.1%	-56.42%	89.1%	2.53%
Cholla Plant Unit 3	2017	8760	271.00	1,258,142	53.1%	120.33%	87.1%	-2.24%
Cholla Plant Unit 3	2018	8760	271.00	1,225,797	51.6%	-2.82%	92.2%	5.86%
Cholla Plant Unit 3	2019	8760	271.00	1,006,969	42.4%	-17.83%	89.3%	-3.15%
Cholla Plant Unit 3	2020	8784	271.00	1,077,072	45.2%	6.60%	92.5%	3.58%
Source: Staff Data Request 1.55								

As shown in the above exhibit, for each year 2010 through 2016, Cholla Unit 1's net capacity factor decreased in each year to a low of 12.1 percent, but then increased substantially (i.e., by

[67] Monthly capacity factor data for APS's generating units is included in the confidential monthly PSA workpapers that were provided in response to Staff data request 1.95.

225.62 percent) to 39.4 percent in 2017. For the period 2018 through 2020, the net capacity factor at Cholla Unit 1 fluctuated from 46.36 percent in 2018 then decreased to 28.7 percent in 2019 before increasing to 39.1 percent in 2020. Cholla Unit 3's EAFs were fairly consistent during the period 2010 through 2020 with the largest decrease (i.e., 11.11 percent) occurring from 2013 to 2014.

With regard to Cholla Unit 3, for each year 2010 through 2016, the net capacity factor decreased in most years to a low of 24.1 percent in 2016 before increasing substantially (i.e., by 120.33 percent) to 53.1 percent in 2017. For the period 2018 through 2020, the net capacity factor at Cholla Unit 3 decreased to 51.6 percent in 2018 then to 42.4 percent in 2019 before increasing to 45.2 percent in 2020. With the exceptions of 2016 (78.4 percent) and 2019 (70.6 percent), Cholla Unit 1's EAFs were fairly consistent during the period 2010 through 2020.

For the month of January 2021, the Company provided the following capacity factor and EAF data for Cholla Units 1 and 3:

Exhibit 4-50
Cholla Plant Capacity Factors and EAFs for January 2021

Generating Unit	Date	Period Hours	Net Max Cap (MW)	Net Generation (MWh)	Net Capacity Factor	Equivalent Availability Factor
Cholla Unit 1	Jan-2021	744	116.00	28,658	33.20%	100.00%
Cholla Unit 3	Jan-2021	744	271.00	36,762	18.20%	72.11%
Souce: Staff Data Request 1.55						

For January 2021, Cholla Unit 1 had a capacity factor of 33.2 percent and an EAF of 100.00 percent. Cholla Unit 3 had a capacity factor of 18.2 percent and an EAF of 72.11 percent.

As it relates to the review period for Cholla, as shown in Exhibits 4-49 and 4-50 above, Unit 1 had capacity factors of 28.7 percent, 39.1 percent and 33.2 percent for 2019, 2020 and for January 2021, respectively. Cholla Unit 1 had EAFs of 70.6 percent, 89.7 percent and 100.0 percent for 2019, 2020 and January 2021, respectively. In addition, Cholla Unit 3 had capacity factors of 42.4 percent, 45.2 percent and 18.2 percent for 2019, 2020 and January 2021, respectively. Cholla Unit 3 had EAFs of 89.3 percent, 92.5 percent and 72.11 percent for 2019, 2020 and January 2021, respectively.

The capacity factors and EAFs for Four Corners Units 4 and 5 for the period 2010 through 2020 are shown in the exhibit below:

Exhibit 4-51
Four Corners Plant Capacity Factors and EAFs for the Period 2010-2020

Generating Unit	Year	Period Hours	Net Max Cap (MW)	Net Generation (MWh)	Net Capacity Factor	Capacity Factor % Change	Equivalent Availability Factor	Equivalent Availability Factor % Change
Four Corners Unit 4	2010	8760	763.3	3,850,708	57.60%		60.37%	
Four Corners Unit 4	2011	8760	770.0	5,191,814	77.00%	33.68%	82.83%	37.20%
Four Corners Unit 4	2012	8784	770.0	5,043,596	74.60%	-3.12%	80.19%	-3.19%
Four Corners Unit 4	2013	8760	770.0	4,609,845	68.30%	-8.45%	74.78%	-6.75%
Four Corners Unit 4	2014	8760	770.0	4,900,124	72.60%	6.30%	76.09%	1.75%
Four Corners Unit 4	2015	8760	770.0	5,267,495	78.10%	7.58%	79.54%	4.53%
Four Corners Unit 4	2016	8784	770.0	3,703,846	54.80%	-29.83%	60.40%	-24.06%
Four Corners Unit 4	2017	8760	770.0	3,879,777	57.50%	4.93%	67.12%	11.13%
Four Corners Unit 4	2018	8760	770.0	3,170,421	47.00%	-18.26%	51.55%	-23.20%
Four Corners Unit 4	2019	8760	770.0	4,874,932	72.30%	53.83%	83.06%	61.13%
Four Corners Unit 4	2020	8784	770.0	4,019,757	59.40%	-17.84%	67.49%	-18.75%
Four Corners Unit 5	2010	8760	770.00	5,840,034	86.60%		89.85%	
Four Corners Unit 5	2011	8760	770.00	5,000,684	74.10%	-14.43%	78.91%	-12.18%
Four Corners Unit 5	2012	8784	770.00	5,139,693	76.00%	2.56%	80.90%	2.52%
Four Corners Unit 5	2013	8760	770.00	4,323,725	64.10%	-15.66%	70.90%	-12.36%
Four Corners Unit 5	2014	8760	770.00	3,836,066	56.90%	-11.23%	60.19%	-15.11%
Four Corners Unit 5	2015	8760	770.00	4,904,756	72.70%	27.77%	76.85%	27.68%
Four Corners Unit 5	2016	8784	770.00	3,166,815	46.80%	-35.63%	53.72%	-30.10%
Four Corners Unit 5	2017	8760	770.00	2,642,880	39.20%	-16.24%	46.54%	-13.37%
Four Corners Unit 5	2018	8760	770.00	4,338,425	64.50%	64.54%	71.80%	54.28%
Four Corners Unit 5	2019	8760	770.00	4,042,415	59.90%	-7.13%	70.54%	-1.75%
Four Corners Unit 5	2020	8784	770.00	3,579,220	52.90%	-11.69%	60.33%	-14.47%
Source: Staff Data Request 1.55								

As shown in the above exhibit, for each year 2010 through 2016, Four Corners Unit 4's net capacity factor fluctuated modestly in each year until decreasing to 54.8 percent in 2016. For the period 2017 through 2020, the net capacity factor at Four Corners Unit 4 fluctuated from 57.5 percent in 2017 then decreased to 47.0 percent in 2018, increased to 72.3 percent in 2019 then decreased again to 59.4 percent in 2020. Four Corner Unit 4's EAFs were fairly consistent during the period 2010 through 2015 but then decreased sharply to 60.4 percent in 2016. For the period 2017 through 2020, Unit 4's EAF fluctuated and increased to a high of 83.6 percent in 2019 before decreasing to 67.49 percent in 2020.

With regard to Four Corners Unit 5, for each year 2010 through 2020, the net capacity factors fluctuated up and down and increased substantially to 64.5 percent in 2018 before decreasing modestly in 2019 and 2020. Four Corner Unit 5's EAFs fluctuated up and down during the period 2010 through 2017 but then increased sharply to 71.8 percent in 2018 then decreased to 70.54 percent and 60.33 percent in 2019 and 2020, respectively.

For the month of January 2021, the Company provided the following capacity factor and EAF data for Four Corners Units 4 and 5:

Exhibit 4-52
Four Corners Plant Capacity Factors and Equivalent Availability Factors for January 2021

Generating Unit	Date	Period Hours	Net Max Cap (MW)	Net Generation (MWh)	Net Capacity Factor	Equivalent Availability Factor
Four Corners Unit 4	Jan-2021	744	770.00	468,835	81.80%	96.40%
Four Corners Unit 5	Jan-2021	744	770.00	400,331	69.90%	81.11%
Source: Staff Data Request 1.55						

For January 2021, Four Corners Unit 4 had a capacity factor of 81.8 percent and an EAF of 96.4 percent. Four Corners Unit 5 had a capacity factor of 69.9 percent and an EAF of 81.11 percent.

As it relates to the review period for Four Corners, as shown in Exhibits 4-51 and 4-52 above, Unit 4 had capacity factors of 72.3 percent, 59.4 percent and 81.8 percent for 2019 2020 and for January 2021, respectively. Four Corners Unit 4 had EAFs of 83.1 percent, 67.5 percent and 96.4 percent for 2019, 2020 and January 2021, respectively. In addition, Four Corners Unit 5 had capacity factors of 59.9 percent, 52.9 percent and 69.9 percent for 2019, 2020 and January 2021, respectively. Four Corners Unit 5 had EAFs of 70.5 percent, 60.3 percent and 81.1 percent for 2019, 2020 and January 2021, respectively.

The capacity factors and EAFs for Navajo Units 1-3 for the period 2010 through 2019[68] are shown in the exhibit below:

[68] Navajo Units 1-3 were retired in the fourth quarter of 2019.

Exhibit 4-53
Navajo Plant Capacity Factors and Equivalent Availability Factors for the Period 2010-2019

Generating Unit	Year	Period Hours	Net Max Cap (MW)	Net Generation (MWh)	Net Capacity Factor	Capacity Factor % Change	Equivalent Availability Factor	Equivalent Availability Factor % Change
Navajo Unit 1	2010	8760	750.0	5,948,415	90.50%		94.70%	
Navajo Unit 1	2011	8760	750.0	4,858,253	73.90%	-18.34%	77.44%	-18.23%
Navajo Unit 1	2012	8784	750.0	5,294,934	80.40%	8.80%	95.35%	23.13%
Navajo Unit 1	2013	8760	750.0	5,832,397	88.80%	10.45%	96.14%	0.83%
Navajo Unit 1	2014	8760	750.0	5,586,908	85.00%	-4.28%	89.25%	-7.17%
Navajo Unit 1	2015	8760	750.0	5,013,421	76.30%	-10.24%	96.81%	8.47%
Navajo Unit 1	2016	8784	750.0	4,220,475	64.10%	-15.99%	91.40%	-5.59%
Navajo Unit 1	2017	8760	750.0	4,352,272	66.20%	3.28%	82.41%	-9.84%
Navajo Unit 1	2018	8760	750.0	4,329,137	65.90%	-0.45%	87.48%	6.15%
Navajo Unit 1	2019	7674.85	750.0	3,435,209	59.70%	-9.41%	81.66%	-6.65%
Navajo Unit 1	2020	0	0.0	-	0.00%	-100.00%	0.00%	-100.00%
Navajo Unit 2	2010	8760	750.00	4,646,171	70.70%		73.68%	
Navajo Unit 2	2011	8760	750.00	5,941,446	90.40%	27.86%	94.85%	28.73%
Navajo Unit 2	2012	8784	750.00	5,328,241	80.90%	-10.51%	95.94%	1.15%
Navajo Unit 2	2013	8760	750.00	5,284,644	80.40%	-0.62%	86.48%	-9.86%
Navajo Unit 2	2014	8760	750.00	6,013,941	91.50%	13.81%	98.33%	13.70%
Navajo Unit 2	2015	8760	750.00	4,621,969	70.30%	-23.17%	89.25%	-9.23%
Navajo Unit 2	2016	8784	750.00	3,880,299	58.90%	-16.22%	77.31%	-13.38%
Navajo Unit 2	2017	8760	750.00	4,812,496	73.20%	24.28%	92.77%	20.00%
Navajo Unit 2	2018	8760	750.00	4,351,152	66.20%	-9.56%	89.14%	-3.91%
Navajo Unit 2	2019	7716.15	750.00	3,433,908	59.30%	-10.42%	83.32%	-6.53%
Navajo Unit 2	2020	0	0.00	-	0.00%	-100.00%	0.00%	-100.00%
Navajo Unit 3	2010	8759	750.00	5,835,007	88.80%		91.95%	
Navajo Unit 3	2011	8760	750.00	5,619,907	85.50%	-3.72%	97.57%	6.11%
Navajo Unit 3	2012	8784	750.00	5,264,864	79.90%	-6.55%	87.96%	-9.85%
Navajo Unit 3	2013	8760	750.00	6,020,834	91.60%	14.64%	98.13%	11.56%
Navajo Unit 3	2014	8760	750.00	5,630,891	85.70%	-6.44%	91.30%	-6.96%
Navajo Unit 3	2015	8760	750.00	3,910,320	59.50%	-30.57%	77.08%	-15.58%
Navajo Unit 3	2016	8784	750.00	3,738,297	56.70%	-4.71%	88.71%	15.09%
Navajo Unit 3	2017	8760	750.00	4,644,208	70.70%	24.69%	90.77%	2.32%
Navajo Unit 3	2018	8760	750.00	4,334,471	66.00%	-6.65%	88.57%	-2.42%
Navajo Unit 3	2019	6888.25	750.00	3,179,871	61.60%	-6.67%	89.40%	0.94%
Navajo Unit 3	2020	0	0.00	-	0.00%	-100.00%	0.00%	-100.00%
Source: Staff Data Request 1.55								

As shown in the above exhibit, for each year 2010 through 2019, Navajo Unit 1's net capacity factor fluctuated with the most substantial decreases occurring from 2010 to 2011 (a decrease of 18.34 percent) and from 2015 to 2016 (a decrease of 15.99 percent). The lowest capacity factor at Unit 1 during the nine-year period was 59.70 percent, which occurred in 2019 (the year Unit 1 was retired). Navajo Unit 1's EAFs fluctuated modestly during the period 2010 through 2019 with the largest changes occurring from 2010 to 2011 (a decrease of 18.23 percent) and from

2011 to 2012 (an increase of 23.13 percent), but never went below 77.44 percent (2011). Navajo Unit 1 was retired on November 16, 2019, thus there was no capacity factor or EAF data for 2020 and beyond.

With regard to Navajo Unit 2, for each year 2010 through 2019, the net capacity factors fluctuated with substantial increases occurring from 2010 to 2011 (27.86 percent) and from 2016 to 2017 (24.28 percent). Substantial decreases in capacity occurred from 2014 to 2015 (23.17 percent) and from 2015 to 2016 (16.22 percent). The lowest capacity factor at Unit 2 during the nine-year period was 58.90 percent, which occurred in 2016. Unit 2's EAFs fluctuated up and down during the period 2010 through 2019, but increased substantially from 2010 to 2011 (28.73 percent) and from 2016 to 2017 (20.00 percent), but never went below 73.68 percent (2010). Navajo Unit 2 was retired on November 18, 2019, thus there was no capacity factor or EAF data for 2020 and beyond.

With regard to Navajo Unit 3, for each year 2010 through 2019, the net capacity factors fluctuated with the most substantial increases occurring from 2012 to 2013 (14.64 percent) and from 2016 to 2017 (24.69 percent). A substantial decrease in capacity occurred from 2014 to 2015 (30.57 percent). The lowest capacity factor at Unit 3 during the nine-year period was 56.70 percent, which occurred in 2016. Unit 3's EAFs fluctuated up and down during the period 2010 through 2019, with the most substantial increases occurring from 2012 to 2013 (11.56 percent) and from 2015 to 2016 (15.09 percent), but never went below 77.08 percent (2015). Navajo Unit 3 was retired on October 15, 2019, thus there was no capacity factor or EAF data for 2020 and beyond.

As it relates to the review period for Navajo, as previously noted, Navajo Units 1-3 were retired in October and November 2019, thus there was no capacity or EAF data for 2020 or January 2021. As shown in Exhibit 4-53 above, for 2019, (1) Unit 1 had a capacity factor and an EAF of 59.7 percent and 81.7 percent, respectively, (2) Unit 2 had a capacity factor and an EAF of 59.3 percent and 83.3 percent, respectively, and (3) Unit 3 had a capacity factor and an EAF of 61.6 percent and 89.4 percent, respectively, for 2019.

Conclusion

There was no clear trend in the capacity factors or EAFs for Cholla and Four Corners in 2019 or 2020, or for Navajo in 2019. As discussed above, the capacity factors and EAFs fluctuated not only over the last ten years (i.e., 2010 through 2020), but also during the review period. We compared the 2019 and 2020 capacity factors for Cholla, Four Corners and Navajo to the benchmarks compiled by the U.S. Department of Energy ("DOE") for 2019 and 2020 as shown in the exhibit below:

Exhibit 4-54
Comparison of 2019 and 2020 Capacity Factors for Cholla, Four Corners and Navajo to U.S. Department of Energy Benchmarks

Description	2019 Cholla Unit 1	2019 Cholla Unit 3	2019 Four Corners Unit 4	2019 Four Corners Unit 5	2019 Navajo Unit 1	2019 Navajo Unit 2	2019 Navajo Unit 3		2019 Benchmark Per US DOE
Capacity Factor	28.7%	42.4%	53.8%	59.9%	59.7%	59.3%	61.6%		47.5%
Description	**2020 Cholla Unit 1**	**2020 Cholla Unit 3**	**2020 Four Corners Unit 4**	**2020 Four Corners Unit 5**	**2020 Navajo Unit 1**	**2020 Navajo Unit 2**	**2020 Navajo Unit 3**		**2020 Benchmark Per US DOE**
Capacity Factor	39.1%	45.2%	59.4%	52.90%	N/A	N/A	N/A		40.2%
Source: Cholla, Four Corners and Najajo capacity factors per the response to Staff Data Request 1.55									

As shown in the above exhibit, other than Cholla Unit 1 in 2019, the capacity factors for Cholla and Four Corners in 2019 and 2020 (and 2019 only for Navajo) were in line with, or above the DOE benchmarks for 2019 and 2020. We performed a similar analysis with regard to APS's sources of generation other than coal (i.e., nuclear, natural gas, renewables) and noted that the capacity factors of these generating units were generally in line with the DOE benchmarks for 2019 and 2020.

As for the impacts on ratepayers, despite the noted fluctuations in capacity factors and EAFs discussed above, there were no customer outages attributable to a lack of power supply during the review period.[69] It should also be noted that APS did not experience any disruptions in its coal supply during the review period.[70]

PSA Filings, Supporting Workpapers And Documentation

Documentation relating to the review of supporting workpapers for calculations in the monthly PSA filings and general ledger detail for the review period was requested in several data requests (i.e., Staff data request 1.96 through Staff data request 1.104). The responses to these various data requests all referred to the response to Staff data request 1.95, which contained two sets of Excel files for each month of the review period. Specifically, the Company provided its public PSA filings for each month from January 2019 through January 2021 as well as confidential PSA workpapers, also for each month from January 2019 through January 2021.

The majority of the schedules associated with the public PSA filings are discussed in the PSA POA and include the following:

1. Schedule 1 - PSA Rate Calculation: The PSA rate is the sum of three components including the (1) Forward Component, (2) Historical Component, and (3) Transition Component.
2. Schedule 2 - PSA Forward Component Rate Calculation: This component recovers or refunds differences between the expected PSA Year's[71] costs to those embedded in rates.

[69] See the response to Staff data request 1.43.
[70] See the response to Staff data request 1.123.
[71] The period February 1 through January 31 constitutes the PSA Year.

3. Schedule 3 - PSA Year Forward Component Tracking Account: This account records APS's over/under recovery of its actual PSA Costs on a monthly basis as compared to the actual Base PSA costs recovered in revenue and Forward Component revenue, plus applicable interest.
4. Schedule 4 - PSA Historical Component Rate Calculation: An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose is to provide a true-up mechanism to reconcile any under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.
5. Schedule 5 - Historical Component Tracking Account: This account records the account balance to be collected on a monthly basis pursuant to the Historical Component rate as compared to the actual Historical Component revenues, plus applicable interest.
6. Schedule 6 - PSA Transition Component Rate Calculation: An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.
7. Schedule 7 - PSA Transition Tracking Account: This account records the account balance to be collected on a monthly basis pursuant to the Transition Component as compared to the actual Transition Component revenues, plus applicable interest.
8. Schedule 8 - Summary of Monthly Calculations: This schedule presents a summary of the monthly calculations from Schedules 3, 4 and 5.
9. Schedule 9 - Native Load Customer Counts, Sales and Revenue: This schedule summarizes the Company's monthly customer counts, sales and revenues by rate class.

It should be noted that for all months of the review period, the Company did not utilize Schedules 7 nor 8 in the public PSA filings. The public PSA filings contained other tabs with supporting data including: (1) Beaucoup, (2) Deferral Detail, (3) Deferral Detail Chemical, (4) Deferral Detail SO2, and (5) PSA Amort. During a Microsoft Teams meeting on October 29, 2021 (see additional discussion below), the Company stated that these additional tabs are comprised of internal accounting records that feed into the schedules in the public PSA filings.

With regard to the confidential PSA workpapers, as discussed in Chapter 1, these confidential workpapers were created pursuant to Recommendations III-1 and III-3 from the prior fuel audit. The confidential PSA workpapers are comprised of several worksheets with data culminated from several sources. Specifically, the worksheet tabs from the confidential PSA filings include the following:

Summary Tab: The purpose of this page, which pulls data from other internal worksheets, is to show energy, dollars and average cost for the various generation sources and purchased power.

Energy Transactions Tab: The purpose of the data in this tab is to allocate the purchased power into three categories (i.e., Long-Term, Market, and Other Purchases) and to account for how much purchased power was used for off-system sales.

Off-System Margins Tab: This tab is included to address Item C, Number 1 on page 9 of the PSA POA, which is to provide an itemization of off-system sales margins per buyer.

Margin Explanations Tab: This tab is included to address Item C, Number 2 on page 9 of the PSA POA, which is to provide details on negative off-system sales margins.

Generation (2) Tab: This tab is included to address Item A, Numbers 1-3 and 5-6 on page 9 of the PSA POA and which compiles information from the Gen Details and Fuel Expense worksheets, including generation, cost, heat rate and EFOR for each generating unit.

Gas Costs Tab: This tab is included to address Item D on pages 9-10 of the PSA POA. The data on this tab is provided by Back Office Accounting.

Outage Costs Tab: This tab is included to address Item E, Number 2 on page 10 of the PSA POA, which requires a summary of unplanned outage costs by resource type.

Outages Tab: This tab is included address Item A, Number 4 on page 9 of the PSA POA. The data on this tab is provided by FBO-Fossil.

Filing Forecast Tab: This tab is included to address Item E, Number 1 on page 10 of the PSA POA, and which shows forecasted PSA collections, balances and rates for the next 12 months.

Balance Graph Tab: This tab shows the PSA balance from the Filing Forecast Tab graphically.

PSA Cost Detail Tab: This tab is included to address Item E, Numbers 4-5 on page 10 of the PSA POA. This tab provides a reconciliation between the confidential and non-confidential PSA filings.

There are additional tabs included in the confidential PSA filing workpapers, which the Company indicated are inputs that were created during the monthly billing process and include the following:

- Generation – APS stated that this tab no longer applies and should be retired from the PSA workpapers.
- Gen Details – provided by FBO – Fossil
- Purchased Power – report from EASR used in the monthly close process
- Fuel Expense – provided by Generation Accounting
- Outage Summary – created as part of the monthly close process and the data is used in variance reporting
- Deferred Fuel – source is accounting records
- Level 3 – accounting records (general ledger detail per the response to Staff data request 1.97)
- Level 3 Tie Out – Summary of the Level 3 data, which is used to assist in identifying the inputs related to the energy transactions detail and assists APS in completing its internal analysis.

- Fuel Variance – OL – summary table from the Fuel Variance report, which is used in the monthly close process and variance reporting
- Fuel Variance – NLHL – summary table from the Fuel Variance report, which is used in the monthly close process and variance reporting.
- Fuel Variance – OS – summary table from the Fuel Variance report, which is used in the monthly close process and variance reporting

Due to the complexity of the public PSA filings and the confidential PSA workpapers, coupled with the fact that many of the amounts in both the public PSA filings and confidential workpapers are hardcoded and do not use Excel formulas or links between files, we requested that APS arrange a virtual meeting through Microsoft Teams (or similar) to conduct a walkthrough of the public PSA filings and related confidential PSA workpapers by using the August 2020 PSA documentation so that we could obtain an understanding of the sources for the costs and revenues contained therein and how they are specifically factored into the PSA rates (i.e., the public PSA filings).[72] Pursuant to our request, APS conducted the walkthrough during the aforementioned Microsoft Teams meeting on October 29, 2021.

As noted, the August 2020 public and confidential PSA data was used for the walkthrough. During the walkthrough meeting, the Company stated that data issues were detected in the confidential PSA workpapers for August 2020, but that the error was in presentation only and did not impact PSA rates. In addition, APS stated that this error was only reflected in the August 2020 PSA workpapers.

For the walkthrough, the Company discussed all of the schedules and related tabs in the August 2020 public PSA filing as well as all of the tabs in the confidential PSA workpapers.[73] In terms of the relationship between the public PSA filings and confidential PSA workpapers, as noted above, the PSA Cost Detail tab provides a reconciliation between the confidential and non-confidential PSA filings. This tab lists the items that are excluded from the PSA (e.g., FASB 133 mark-to-market costs) to derive the amounts that flow to the public PSA filings. Specifically, net system fuel and purchased power costs, net system excess sales revenue and native load energy sales (in MWh) flow to Schedule 3 at lines 7, 12 and 4, respectively.

Upon reviewing the confidential monthly PSA workpapers, for the majority of the months of the review period, Larkin was able to tie out the amounts reflected on the PSA Cost Detail tab in the confidential PSA workpapers to the public PSA filings. However, in some instances, we noted inconsistent information between what was reflected on the PSA Cost Detail Tab in the confidential PSA workpapers to what was reported on Schedule 3 from the public monthly PSA filings.

For example, upon reviewing the public and confidential PSA filing and workpapers for January 2021, we noted that on the PSA Cost Detail Tab (from the confidential PSA workpapers) the amount listed on line 37 for Native Load Power Supply Energy was $1,958,001. The note for this line item stated that this amount is reflected on Schedule 3, line 4 for January 2021 on the public PSA filing for that period. However, Schedule 3 from the January 2021 public PSA filing shows the amount of $2,010,166 on line 4 for January 2021 with the $1,958,001 referenced

[72] See the response to Staff data request 5.5.

[73] APS stated that the public and confidential PSA filings and workpapers are set up the same for each month of the review period.

above shown for January 2020. In its response to Staff data request 5.9(b), the Company confirmed that the correct amount for January 2021 was the $2,010,166, which should have been reflected on the PSA Cost Detail Tab for January 2021. As another example, we noted that PSA Cost Detail Tab indicated that chemical costs of $949,000 should be listed on Schedule 3 in the public PSA filing for January 2021, but Schedule 3 reflected $1.024 million for January 2021. In response to Staff data request 5.9(c), APS confirmed that the $1.024 million is the correct amount and should have been reflected on the PSA Cost Detail tab in the confidential PSA workpapers for January 2021. In both these and other instances, the Company conceded these were inadvertent analyst input errors that were subsequently corrected.

Conclusion

With regard to the electronic (i.e., Excel) versions of APS's PSA filings and related confidential PSA workpapers, we found that tying certain amounts among the tabs within the monthly filings (public and confidential) and/or tying amounts from the confidential PSA workpapers to the public PSA filings was challenging due to the Company hard coding data versus using Excel's formula function. Therefore, we recommend that the Company expand its use of Excel's formula function in the PSA related Excel files in order for future auditors of the PSA filings to be able to efficiently analyze the PSA filings and related workpapers in terms tracing amounts to supporting documentation and calculations.

In addition, the input errors in the Company's PSA filings did not have a material impact on the PSA rate. However, between these errors coupled with the data issues that APS indicated were present in the confidential PSA workpapers for August 2020, we recommend that APS develop and/or enhance its existing internal review procedures in order to avoid input errors when compiling the monthly PSA filings and related confidential PSA workpapers.

Review Related To Hedging Activities

As discussed in Chapter 3, APS has an established hedging program for its gas purchases, the primary purpose of which is to reduce natural gas pricing volatility. As previously discussed, beginning in 2020, APS temporarily suspended its hedging activities for years 4 and 5 of its hedging program due to economic uncertainties and consideration of clean energy standards across the Western Region. As noted in Chapter 3, we find that the Company's decision to suspend its hedging activities for years 4 and 5 was reasonable.

Upon reviewing the Company's PSA filings and confidential workpapers, we noted that hedging activities were reflected in each month of 2020 and January 2021. We asked APS to explain why hedging activities were reflected in the 2020 and January 2021 PSA filings and workpapers. In response to Staff data request 5.3, the Company stated that while years 4 and 5 of its hedging program have been temporarily suspended, APS still maintained its hedging activities for year 1-3 of its program. This time frame included APS performing hedges in 2020 and 2021in order to ensure that the hedge percentages for years 1-3 were in compliance with the Company's hedging policy. In addition, APS stated that years 4 and 5 of its hedging program are calendar years 2024 and 2025[74], so the temporary suspension did not impact hedging transactions during the review period.

[74] See the response to Staff data request 5.3(b).

In its response to Staff data request 1.16, the Company provided confidential attachment APS21FA00104, which is a 13-page document titled "Process: Commodity Hedge Compliance Process", the stated purpose of which is as follows:

> The purpose of this process is to identify and implement the hedge plan to fulfill the compliance requirement of the APS System Hedge Policy. This process is used to review and verify compliance with the five periods of hedge compliance deadlines for the measurement of the System Hedge Policy.

Upon reviewing this document, we find that APS's procedures for its hedging activities are reasonable. We asked APS whether the hedging processes discussed in the Commodity Hedge Compliance Process document are incorporated into the monthly PSA filings during the review period. In its response to Staff data request 4.5, the Company stated:

> The Commodity Hedge Compliance Process demonstrated in Attachment APS21FA00104 is used to ensure that Traders are within hedge percentage tolerance as of a defined measurement period. These hedge percentages are defined as part of the Hedge Policy provided in Staff 1.108 (Attachment APS21 FA00287). Although the Hedge Compliance Process helps to moderate the risks of hedging, there is not a direct reconciliation of those figures within the PSA filings provided in Staff 1.95. The PSA filings will reflect the costs of the hedging transactions that are measured by the Hedge Compliance Process. The Hedge Compliance Process will ensure that those hedging costs were incurred within the constructs of the APS Hedge Policy.

We reviewed confidential attachment APS21FA00287 from the response to Staff data request 1.108, which is replicated in the exhibit below:

Exhibit 4-55
System Hedge Strategy Compliance –OATI

[redacted]

[redacted] As for the Current Hedge Percent, APS stated that that these percentages were in compliance at trade inception based on a BAL Report[75] dated November 12, 2019 and are considered in compliance until the next annual compliance period.[76] As to whether the System Hedge Compliance Reports (i.e., Exhibit 4-55 above) tie to the hedging activities in the monthly PSA filings, in response to Staff data request 4.5, the Company stated that the System Hedge Compliance Reports reflect a point in time measurement of compliance with hedge percentages and do not factor into the Company's financial information.

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[75] The BAL Reports are discussed in the section of Chapter 4 that discusses APS's simulation models.

[76] See confidential attachment APS21FA00287 from the response to Staff data request 1.108.

With regard to the hedging activities reflected in the PSA workpapers, we noted that the confidential Excel PSA workpapers provided in Staff data request 1.95 included a tab titled "Gas Costs", which is a schedule called Actual Natural Gas Fuel Costs. In addition to physical gas costs, this schedule also breaks out APS's individual hedging activities by (1) long-term purchases (one month or longer), (2) short-term purchases (spot market and less than one month), (3) short-term sales (spot market and less than one month), and (4) prior period adjustments. The exhibit below summarizes the Company's hedging activities by the foregoing categories for each month of the review period:

Exhibit 4-56
Summary of Hedging Activities During the Period January 2019 through January 2021

Description	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Total Long Term Hedges	$ (374,023)	$ 1,211,624	$2,256,386	$ 3,304,944	$4,590,048	$3,229,486	$ 5,522,516	$ 5,944,592	$ 5,412,399	$4,471,882	$ 3,752,973	$ 2,873,195	$42,196,022
Total Short Term Hedges	$ 1,603	$ (983,116)	$ (350)	$ (60,444)	$ (321,511)	$ (160,308)	$ (41,000)	$ (73,074)	$ (81,030)	$ (154,607)	$ -	$ -	$ (1,873,835)
Prior Period Adjustments	$ -	$ 6,372	$ (9,877)	$ (4,487)	$ (5,200)	$ (1,374)	$ (13,233)	$ (12,250)	$ (10,091)	$ (8,425)	$ (19,492)	$ 43,130	$ (34,927)
Total Hedging Liquidations	$ (372,420)	$ 234,880	$2,246,159	$ 3,240,013	$4,263,337	$3,067,804	$ 5,468,283	$ 5,859,269	$ 5,321,278	$4,308,851	$ 3,733,481	$ 2,916,325	$40,287,259

Description	January 2020	February 2020	March 2020	April 2020	May 2020	June 2020	July 2020	August 2020	September 2020	October 2020	November 2020	December 2020	Total 2020
Total Long Term Hedges	$ 4,029,886	$ 4,397,611	$5,139,917	$ 7,414,128	$4,470,510	$7,396,133	$11,981,345	$ 8,300,497	$ 1,261,839	$3,406,111	$(1,442,100)	$ (806,429)	$55,549,448
Total Short Term Hedges	$ (72,090)	$ -	$ (128,246)	$ (697,578)	$ (915)	$ (131,788)	$ -	$ (358,101)	$ (72,315)	$ (146,686)	$ (25,200)	$ (350,546)	$ (1,983,464)
Prior Period Adjustments	$ (13,059)	$ (71,054)	$ (8,082)	$ -	$ -	$ (101,400)	$ (104,780)	$ (86,180)	$ 14,100	$ -	$ (4,173)	$ -	$ (374,628)
Total Hedging Liquidations	$ 3,944,737	$ 4,326,557	$5,003,589	$ 6,716,551	$4,469,596	$7,162,945	$11,876,565	$ 7,856,216	$ 1,203,624	$3,259,425	$(1,471,473)	$(1,156,975)	$53,191,357

Description	January 2021
Total Long Term Hedges	$ 1,557,358
Total Short Term Hedges	$ (164,025)
Prior Period Adjustments	$ 4,934
Total Hedging Liquidations	$ 1,398,267

Source: Staff Data Request 1.95 from the Gas Costs Tab

We tied the amounts shown in the above exhibit back to the Company's monthly fuel expense reports that are prepared by the Generation Accounting. Except for as discussed below, no exceptions were noted. For August and September 2019, we noted that the hedging liquidation costs reflected on the Gas Costs tab did not agree with what was reported in APS's monthly fuel expense reports. However, the differences between the Gas Costs tab and fuel expense reports for August and September 2019 each totaled $87,450 (positive and negative, respectively) and thus netted to $0 as shown in the exhibit below.

Exhibit 4-57
Hedging Liquidation Cost Differences for August and September 2019

Description	August 2019	September 2019	Net
Total Hedging Liquidations per Gas Costs Tab	$ 5,859,269	$5,321,278	
Total Hedging Liquidations per Fuel Expense Report	$ 5,771,819	$5,408,728	
Difference	$ 87,450	$ (87,450)	$ 0
	February 2020		
Total Hedging Liquidations per Gas Costs Tab	$ 4,326,557		
Total Hedging Liquidations per Fuel Expense Report	$ 4,356,659		
Difference	$ (30,102)		

For February 2020, we also noted the credit difference of $30,102 shown above between the hedging liquidation costs reflected on the Gas Costs tab to the fuel expense report. However, as shown in Exhibit 4-59 below, the $30,102 represents a reclass amount, which when applied, netted to the $4,326,557 of hedging liquidation costs shown on the Gas Cost tab for February 2020.

In its response to Staff data request 1.100, the Company provided Attachment APS21FA00102, which APS stated provides a guideline to the PSA supporting workpapers. With regard to hedging activities, this PSA guideline states:

> Please see Gas Fuel Cost Summaries and Gas Native Load Hedge file for supporting documentation of Actual Natural Gas Fuel Costs page of the Monthly Confidential PSA Report.

We requested that APS provide the Gas Fuel Cost Summaries and Gas Native Load Hedge supporting documentation for the hedging activities included in the monthly Actual Natural Gas Fuel Costs schedules in the confidential PSA workpapers, which the Company provided in its response to Staff data request 4.6. The exhibit below replicates the Gas Fuel Cost Summaries referenced in the PSA guideline referenced above:

Exhibit 4-58
Gas Fuel Cost Summaries for the Period January 2019 through January 2021

						Other Charges Accounted for as Gas Fuel Cost				
Date	Gas Physical	Prior Month TU	Other	Oct Test Energy	Total Cost Before Hedge	Fixed Reservation	Prior Month TU	Gas Storage Demand	Gas Handling	Total Other
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
Jan-2019	16,445,367	(81,528)		(57,440)	16,306,399	4,929,552	6,207	55,500	65,999	5,057,259
Feb-2019	12,843,755	178,763		(67,755)	12,954,764	4,467,680	(0)	55,500	69,991	4,593,171
Mar-2019	11,769,708	66,484		(705,167)	11,131,025	4,196,024	(3,000)	55,500	77,747	4,326,271
Apr-2019	5,065,994	13,663		(837,221)	4,242,436	5,427,789	(71,464)	55,500	76,830	5,488,655
May 2019	5,940,749	35,335		52,094	6,028,178	6,228,682	-	74,000	94,512	6,397,194
Jun-2019	10,583,713	93,310	30,796	202,054	10,909,874	7,222,146	(0)	76,000	74,582	7,372,728
Jul-2019	17,374,461	47,485		-	17,421,947	7,950,933	0	76,200	104,347	8,131,480
Aug-2019	19,431,732	(467,672)	(9,982)	-	18,954,078	8,012,677	(8,548)	75,800	106,909	8,186,839
Sep-2019	16,989,505	14,955	87,490	-	17,091,950	7,393,201	(6,884)	76,000	95,970	7,558,287
Oct-2019	15,602,988	61,431		-	15,664,419	5,784,738	9,228	76,000	102,252	5,972,219
Nov-2019	8,935,028	(87,098)		-	8,847,931	4,538,835	7,664	57,000	96,267	4,699,766
Dec-2019	17,030,197	5,209	(115,045)	-	16,920,361	4,917,341	2,191	57,000	103,629	5,080,161
Jan-2020	13,436,654	(25,108)		-	13,411,546	4,926,912	369	57,000	78,719	5,062,999
Feb-2020	9,052,157	113,424	30,101	-	9,195,681	4,548,770	1,426	57,000	92,148	4,699,345
Mar-2020	5,484,253	40,632		-	5,524,885	4,193,865	0	57,000	95,208	4,346,073
Apr-2020	6,629,747	(54,811)	1,585	-	6,576,521	6,322,009	(5,076)	57,000	102,334	6,476,267
May 2020	13,224,298	13,911	(1,585)	-	13,236,624	7,131,900	(5,194)	76,000	96,864	7,299,570
Jun-2020	15,718,659	72,724		-	15,791,383	8,117,872	0	76,000	99,929	8,293,801
Jul-2020	21,597,385	(55,698)		-	21,541,687	8,848,672	248	76,000	94,058	9,018,978
Aug-2020	25,293,033	6,326		-	25,299,359	8,904,739	356	76,000	89,566	9,070,661
Sep-2020	22,738,774	(5,783)		-	22,732,991	8,295,711	3,454	76,000	83,230	8,458,395
Oct-2020	14,396,912	143,668		-	14,540,580	6,051,524	5,330	76,000	93,950	6,226,804
Nov-2020	18,579,177	(12,700)	(54,654)	-	18,511,823	4,513,063	(5,822)	57,000	77,845	4,642,085
Dec-2020	17,743,484	63,192		-	17,806,676	4,909,961	(5,172)	57,000	112,342	5,074,130
Jan-2021	16,323,019	(38,152)		-	16,284,867	4,928,196	(10,319)	57,000	87,875	5,062,752
	358,230,751	141,962	(31,294)	(1,413,435)	356,927,985	152,762,791	(85,005)	1,645,000	2,273,103	156,595,889

Source: Staff Data Request 4.6, Attachment APS21FA00308

As shown in the above exhibit, for each month of the review period, the amounts shown in columns A-E reflect APS's monthly physical gas purchases and other gas costs before hedges. We tied the total gas costs before hedges reflected in column E to the Actual Natural Gas Fuel Costs schedule that is included in the confidential PSA workpapers. No exceptions were noted. As it relates to the other charges accounted for as gas fuel costs shown in columns F-I, these amounts represent firm reservation charges [redacted] including all other items accounted for as fixed reservation and storage capacity costs.[77] We tied the total other costs reflected in column J to the Actual Natural Gas Fuel Costs schedule that is included in the confidential PSA workpapers. No exceptions were noted.

The exhibit below replicates the Gas Native Load Hedge file referenced in the PSA guideline referenced above:

Exhibit 4-59
Gas Native Load Hedge File for the Period January 2019 through January 2021

Date	Gas Hedge Physical	Gas Hedge Financial	Prior Month TU	Reclass	Gas Hedges
	(A)	(B)	(C)	(D)	(E)
Jan-2019	$ 1,603	$ (366,265)	$ -	$ (7,758)	$ (372,420)
Feb-2019	$ (983,116)	$ 1,210,300	$ (62)	$ 7,758	$ 234,879
Mar-2019	$ 301	$ 2,253,003	$ (7,144)	$ -	$ 2,246,159
Apr-2019	$ 16,074	$ 3,223,950	$ (11)		$ 3,240,013
May 2019	$ 195,217	$ 4,068,130	$ (10)		$ 4,263,337
Jun-2019	$ 7,645	$ 3,056,025	$ 4,134		$ 3,067,804
Jul-2019	$ 7,051	$ 5,464,215	$ (2,982)		$ 5,468,283
Aug-2019	$ (34,297)	$ 5,893,565	$ 0		$ 5,859,269
Sep-2019	$ (31,367)	$ 5,352,300	$ 345		$ 5,321,278
Oct-2019	$ (21,694)	$ 4,330,545	$ -		$ 4,308,851
Nov-2019	$ -	$ 3,747,000	$ (13,519)		$ 3,733,481
Dec-2019	$ -	$ 2,916,325	$ -		$ 2,916,325
Jan-2020	$ 31,995	$ 3,912,743	$ -		$ 3,944,738
Feb-2020	$ -	$ 4,335,355	$ 21,304	$ (30,102)	$ 4,326,557
Mar-2020	$ 18,944	$ 4,984,645	$ -		$ 5,003,589
Apr-2020	$ (90,749)	$ 6,807,300	$ -		$ 6,716,551
May 2020	$ (915)	$ 4,470,510	$ -		$ 4,469,596
Jun-2020	$ 2,995	$ 7,159,950	$ -		$ 7,162,945
Jul-2020	$ -	$ 11,876,565	$ -		$ 11,876,565
Aug-2020	$ (260,514)	$ 8,116,730	$ -		$ 7,856,216
Sep-2020	$ (8,226)	$ 1,211,850	$ -		$ 1,203,624
Oct-2020	$ (19,290)	$ 3,278,715	$ -		$ 3,259,425
Nov-2020	$ 2,400	$ (1,469,700)	$ (4,173)	$ -	$ (1,471,473)
Dec-2020	$ (675)	$ (1,156,300)	$ -	$ -	$ (1,156,975)
Jan-2021	$ 2,750	$ 1,390,583	$ 4,936	$ -	$ 1,398,269
Total	$ (1,163,868)	$ 96,068,038	$ 2,818	$ (30,102)	$ 94,876,885

Source: Staff Data Request 4.6, Attachment APS21FA00309

As shown in the above exhibit, for each month of the review period, the hedging transactions are broken out by physical gas hedges, financial gas hedges, prior month, and reclassifications to arrive at the total monthly gas hedges reflected in column E. We tied the total gas hedge costs reflected in column E to the Actual Natural Gas Fuel Costs schedule that is included in the confidential PSA workpapers (and summarized in Exhibit 4-56 above). No exceptions were noted.

[77] See the Gas Costs tab in the monthly confidential PSA workpapers provided in Staff data request 1.95.

The gas hedge amounts shown in column E represent hedge liquidations and are included in the Net Native Load Fuel and Purchased Power Expense amounts reflected on the Summary tab of the monthly confidential PSA workpapers and summarized in the table in the Audit Findings section of our report on page 1-2. During a Microsoft Teams meeting on October 29, 2021, which entailed a walkthrough of APS's PSA filings and confidential PSA workpapers, the Company stated that the hedge liquidations are included in the PSA. We verified this by tracing the hedge liquidations amounts from the monthly confidential PSA workpapers to the public PSA filings. No exceptions were noted.

Chemicals and Reagents

As discussed on page 6 of the PSA POA, the production-related environmental chemical costs allowed to be included in the PSA are limited to expenses for lime, sulfur and ammonia used at APS's fossil fuel generation sites. The Base Chemical costs are set at $0.000500 per kWh effective on August 19, 2017 per Commission Decision No. 76295 and calculated as shown in the exhibit below:

Exhibit 4-60
Base Chemical Cost Calculation

Description	2015
Fossil Environmental Chemicals	
Lime	$ 12,976
Sulfur	$ 551
Ammonia - SCR's	$ -
Total Chemical Costs	$ 13,527
2015 Actual Total Retail Load Sales	$ 27,030,686
Chemical Costs in Base Rates	$ 0.000500
Source: Staff Data Request 8.4	

According to the response to Staff data request 8.4, fossil chemical (and water) costs are recorded in FERC Accounts 502 and 549, which corresponds to Section 9 (Allowable Costs) in the PSA POA.

We asked APS to (1) identify which chemicals and reagents are used at each of its generating plants[78], and (2) provide the inventory and cost information for each plant that uses chemicals and/or reagents during each month of the review period.[79] In response to our inquiry, the Company provided voluminous spreadsheets, which show by month, the requested information. However, upon reviewing this monthly data (by plant), we noted that the chemicals and reagents listed included many other chemicals (e.g., carbon, sodium hypochlorite, anodamine, acrylate copolymer, etc.) that are beyond the chemicals allowed in the PSA includable costs (i.e., lime, sulfur and ammonia).

We asked the Company whether chemical and reagent costs other than lime, sulfur and ammonia were included in the monthly PSA filings during the review period. In response to Staff data request 8.4, the Company stated that the voluminous data provided in response to Staff data

[78] Data Request Staff data request 1.119.
[79] Data Request Staff data request 1.120.

requests 1.119 and 1.120 reflects all chemical costs at the Total Plant level and not just APS's portion, and that only lime, sulfur and ammonia were included in the monthly PSA filings. In addition, APS stated that the chemical costs included in PSA are limited to lime, sulfur and ammonia used at fossil fuel generations sites (i.e., Cholla and Four Corners).[80] Based on the foregoing, in response to Staff data request 5.2, APS provided Attachment ExcelAPS21FA00318, which showed the breakout of lime, sulfur and ammonia costs included in the public monthly PSA filings, which is replicated in the exhibit below:

Exhibit 4-61
Chemical Costs Included in the PSA

Description	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	July 2019	August 2019	September 2019	October 2019	November 2019	December 2019	Total 2019
Four Corners													
Ammonia	$ 361,337	$ 499,739	$ (69,434)	$ 355,012	$ 262,692	$ 248,079	$ 679,539	$ 529,006	$ 407,912	$ 333,592	$ 321,536	$ 216,042	$ 4,145,052
Lime	$ 606,027	$ 702,194	$ 250,816	$ 663,416	$ 688,290	$ 770,801	$ 1,001,700	$ 718,958	$ 806,882	$ 778,494	$ 611,407	$ 527,051	$ 8,126,034
Sulfur	$ 36,178	$ 21,671	$ 14,532	$ 28,902	$ 35,924	$ 28,782	$ 28,686	$ 21,589	$ 21,617	$ 21,729	$ 21,808	$ 28,937	$ 310,355
Labor	$ 33,876	$ 24,374	$ 23,094	$ 24,528	$ 28,261	$ 26,077	$ 30,522	$ 26,130	$ 26,625	$ 28,937	$ 26,317	$ 28,568	$ 327,309
Four Corners Total	$ 1,037,417	$ 1,247,978	$ 219,008	$ 1,071,859	$ 1,015,167	$ 1,073,738	$ 1,740,448	$ 1,295,682	$ 1,263,037	$ 1,162,751	$ 981,068	$ 800,598	$ 12,908,750
Cholla	$ 201,901	$ 201,902	$ 201,903	$ 201,904	$ 201,905	$ 201,906	$ 201,907	$ 201,908	$ 201,909	$ 201,910	$ 201,911	$ 201,912	$ 2,422,878
Lime	$ 64,621	$ 53,024	$ 280,058	$ 163,528	$ 125,105	$ 183,969	$ 291,985	$ 302,360	$ 170,363	$ 153,163	$ 304,002	$ 266,767	$ 2,358,945
Sulfur	$ 5,076	$ 3,611	$ 9,986	$ 11,833	$ 10,081	$ -	$ 17,956	$ 17,829	$ 8,419	$ 7,583	$ 13,348	$ 6,723	$ 112,446
Cholla Total	$ 69,697	$ 56,636	$ 290,044	$ 175,360	$ 135,186	$ 183,969	$ 309,941	$ 320,189	$ 178,782	$ 160,746	$ 317,349	$ 273,490	$ 2,471,391
Total APS Chemical Cost	$ 1,107,114	$ 1,304,613	$ 509,052	$ 1,247,219	$ 1,150,354	$ 1,257,707	$ 2,050,389	$ 1,615,871	$ 1,441,819	$ 1,323,497	$ 1,298,417	$ 1,074,088	$ 15,380,141
Description	**January 2020**	**February 2020**	**March 2020**	**April 2020**	**May 2020**	**June 2020**	**July 2020**	**August 2020**	**September 2020**	**October 2020**	**November 2020**	**December 2020**	**Total 2020**
Four Corners													
Ammonia	$ 292,628	$ 313,797	$ 224,116	$ 271,677	$ -	$ 575,884	$ -	$ 616,088	$ 515,472	$ 286,968	$ 175,651	$ 271,242	$ 3,543,525
Lime	$ 782,027	$ 896,425	$ 59,095	$ 645,242	$ 246,441	$ 427,558	$ 1,046,915	$ 563,703	$ 965,814	$ 576,308	$ 430,157	$ 594,111	$ 7,233,797
Sulfur	$ 21,760	$ 14,361	$ 7,174	$ 14,478	$ 14,507	$ 21,468	$ 7,085	$ 21,139	$ 14,275	$ 7,237	$ 22,033	$ 7,339	$ 172,856
Labor	$ 30,773	$ 25,183	$ 21,441	$ 22,949	$ 21,572	$ 24,289	$ 30,085	$ 24,936	$ 29,158	$ 24,684	$ 24,347	$ 22,346	$ 301,763
Four Corners Total	$ 1,127,189	$ 1,249,765	$ 311,826	$ 954,346	$ 282,520	$ 1,049,199	$ 1,084,086	$ 1,225,865	$ 1,524,719	$ 895,198	$ 652,188	$ 895,038	$ 11,251,940
Cholla	$ 202,001	$ 202,002	$ 202,003	$ 202,004	$ 202,005	$ 202,006	$ 202,007	$ 202,008	$ 202,009	$ 202,010	$ 202,011	$ 202,012	$ 2,424,078
Lime	$ 325,797	$ 146,938	$ 202,559	$ 167,920	$ 178,514	$ 140,935	$ 413,222	$ 273,651	$ 315,868	$ 336,389	$ 206,510	$ 52,175	$ 2,760,479
Sulfur	$ 13,303	$ 12,058	$ 12,017	$ 12,064	$ 5,298	$ 9,877	$ 18,911	$ 3,990	$ 20,825	$ 11,407	$ 13,231	$ 1,731	$ 134,714
Cholla Total	$ 339,100	$ 158,997	$ 214,576	$ 179,984	$ 183,812	$ 150,813	$ 432,133	$ 277,641	$ 336,693	$ 347,796	$ 219,741	$ 53,907	$ 2,895,193
Total APS Chemical Cost	$ 1,466,289	$ 1,408,762	$ 526,402	$ 1,134,330	$ 466,332	$ 1,200,012	$ 1,516,219	$ 1,503,506	$ 1,861,413	$ 1,242,995	$ 871,929	$ 948,945	$ 14,147,133
Description	**January 2021**												
Four Corners													
Ammonia	$ 267,142												
Lime	$ 681,240												
Sulfur	$ 21,982												
Labor	$ 30,275												
Four Corners Total	$ 1,000,639												
Cholla	$ 202,101												
Lime	$ 23,301												
Sulfur	$ 107												
Cholla Total	$ 23,409												
Total APS Chemical Cost	$ 1,024,047												
Source: Staff Data Request 5.2													

As shown in the above exhibit, the Company included labor costs in the breakout of the chemical costs associated with Four Corners. In response to our inquiry as to why APS included amounts for labor in the Four Corners chemical costs, the Company stated that labor costs are properly included in the Four Corners chemicals and reagent costs because they must be processed on site by APS employees since such chemicals and reagents are volatile and cannot be transported safely in useable form.[81] With regard to the nature of these labor costs and how they relate to chemical costs included in the PSA, in its response to Staff data request 10.1, the Company stated:

[80] See the response to Staff data request 5.2.

[81] See the response to Staff data request 10.1.

> The management of the chemicals used for environmental controls for Four Corners requires manual labor and operational control manned by trained personnel. Each environmental control has a different process; however, the process in general is as follows: the product is delivered in a dry form (e.g., lime, sulfur and urea) and an employee supervises the off-loading of these chemicals into storage facilities at the plant. The product is transferred to tanks and mixed with water and other chemicals as needed (e.g., to create ammonia and flue-gas desulfurization process liquor) controls at the plant. This process requires an operator to supervise the controls and one or more employees to be in the field monitoring equipment, preventing overflows, and making operational adjustments.

We tied the total monthly amounts shown in the above exhibit to Schedule 3 (PSA Year Forward Component Tracking Account) of the public monthly PSA filings for each month of the review period. No exceptions were noted.

Emission Allowances

APS's coal plants are subject to air emission regulations through both state and federal programs. Throughout the audit period, these coal plants were required to comply with EPA's Cross States Air Pollution Rule ("CSAPR").[82]

APS provided documentation related to the accounting detail associated with costs and revenues, purchases and sales of emission allowances, and monthly emission allowance inventory in the responses to Staff data request 1.132 through Staff data request 1.137. As it relates to the number of emission allowances maintained by APS, the Company stated that it maintains an inventory of California Carbon Allowances ("CCA") to fulfill obligations within California requirements.[83]

Staff data request 1.132 requested that APS provide the Company's emission allowance inventory for each month of calendar years 2019 and 2020 and January 2021. In response to our inquiry, the Company provided its monthly CO_2 emission allowance inventory for the referenced periods. The Company's CO_2 emission allowance activity for the period January through December 2019 is summarized in the exhibit below:

[82] https://www.epa.gov/csapr/cross-state-air-pollution-rule-csapr-regulatory-actions-and-litigation#rule-history

[83] See the response to Staff data request 1.133.

Exhibit 4-62
2019 CO_2 Emission Allowance Activity

Trade Date	Product	[redacted]	Total Value	Inventory Status	Delivery Date	[redacted]	Cumulative Value
		[redacted]	$ 1,235,000			[redacted]	
2/12/2019	I/C-CCA 2018	[redacted]	$ 157,600	Open	2/27/2019	[redacted]	$ 1,277,746
2/15/2019	I/C-CCA 2018	[redacted]	$ 158,400	Open	2/27/2019	[redacted]	$ 1,436,146
2/27/2019	I/C-CCA 2019	[redacted]	$ 238,800	Open	3/27/2019	[redacted]	$ 1,674,946
3/7/2019	I/C-CCA 2019	[redacted]	$ 159,900	Open	3/27/2019	[redacted]	$ 1,834,846
3/28/2019	I/C-CCA 2017	[redacted]	$ 129,760	Open	4/29/2019	[redacted]	$ 1,964,606
4/11/2019	I/C-CCA 2017	[redacted]	$ 84,000	Open	4/29/2019	[redacted]	$ 2,048,606
5/31/2019	I/C-CCA 2019	[redacted]	$ 89,100	Open	6/27/2019	[redacted]	$ 2,137,706
6/19/2019	I/C-CCA 2019	[redacted]	$ 135,520	Open	6/27/2019	[redacted]	$ 2,273,226
7/11/2019	I/C-CCA 2015	[redacted]	$ 87,700	Partial	7/30/2019	[redacted]	$ 2,315,129
7/26/2019	I/C-CCA 2015	[redacted]	$ 86,950	Open	7/30/2019	[redacted]	$ 2,402,079
8/6/2019	I/C-CCA 2016	[redacted]	$ 173,700	Open	8/29/2019	[redacted]	$ 2,575,779
8/21/2019	I/C-CCA 2016	[redacted]	$ 172,900	Open	8/29/2019	[redacted]	$ 2,748,679
8/27/2019	I/C-CCA 2016	[redacted]	$ 86,850	Open	8/29/2019	[redacted]	$ 2,835,529
9/5/2019	I/C-CCA 2015	[redacted]	$ 172,000	Open	9/27/2019	[redacted]	$ 3,007,529
9/13/2019	I/C-CCA 2015	[redacted]	$ 341,800	Open	9/27/2019	[redacted]	$ 3,349,329
10/3/2019	I/C-CCA 2019	[redacted]	$ 85,450	Open	10/30/2019	[redacted]	$ 3,434,779
10/3/2019	I/C-CCA 2019	[redacted]	$ 85,450	Open	10/30/2019	[redacted]	$ 3,520,229
10/10/2019	I/C-CCA 2019	[redacted]	$ 170,200	Open	10/30/2019	[redacted]	$ 3,690,429
11/13/2019	I/C-CCA 2016	[redacted]	$ 136,560	Open	11/26/2019	[redacted]	$ 3,826,989
11/21/2019	I/C-CCA 2016	[redacted]	$ 85,850	Open	11/26/2019	[redacted]	$ 3,912,839
11/1/2019	I/C-CCA 2016	[redacted]	$ 170,300	Open	11/26/2019	[redacted]	$ 4,083,139
12/5/2019	I/C-CCA 2018	[redacted]	$ 85,900	Open	12/30/2019	[redacted]	$ 4,169,039
12/19/2019	I/C-CCA 2018	[redacted]	$ 192,500	Open	12/30/2019	[redacted]	$ 4,361,539
		[redacted]	$ 4,522,190			[redacted]	

Source: Staff Data Request 1.132, Attachment ExcelAPS21FA00087

As shown in the above exhibit, after reflecting beginning balance amounts for quantity and dollars (i.e., prior to 2019) the Company's total CCA inventory was 277,000 CO_2 emission allowances at a total value of $4,522,190. As shown under the Inventory Status column, the majority of the 2019 monthly emission allowances were open. Subsequent to the noted delivery dates, the "open quantity of 2019 emission allowances totaled 265,437 at a cost of $4,361,539. We tied the monthly emission allowance valuations to the Company's general ledger detail. No exceptions were noted.

The Company's emission allowance activity for the period January through December 2020 is summarized in the exhibit below:

Exhibit 4-63
2020 CO_2 Emission Allowance Activity

Trade Date	Product	[redacted]	Total Value	Inventory Status	Delivery Date	[redacted]	Cumulative Value
		[redacted]	$ 3,049,580			[redacted]	
1/2/2020	I/C-CCA 2016	[redacted]	$ 176,800	Open	1/30/2020	[redacted]	$ 3,093,665
1/9/2020	I/C-CCA 2016	[redacted]	$ 89,700	Open	1/30/2020	[redacted]	$ 3,183,365
2/4/2020	I/C-CCA 2018	[redacted]	$ 89,500	Open	2/28/2020	[redacted]	$ 3,272,865
2/19/2020	I/C-CCA 2018	[redacted]	$ 89,450	Open	2/28/2020	[redacted]	$ 3,362,315
3/13/2020	I/C-CCA 2020	[redacted]	$ 102,840	Open	3/31/2020	[redacted]	$ 3,465,155
3/26/2020	I/C-CCA 2020	[redacted]	$ 29,000	Open	3/31/2020	[redacted]	$ 3,494,155
3/26/2020	I/C-CCA 2020	[redacted]	$ 43,500	Open	3/31/2020	[redacted]	$ 3,537,655
6/11/2020	I/C-CCA 2016	[redacted]	$ 167,800	Open	6/29/2020	[redacted]	$ 3,705,455
8/28/2020	I/C-CCA 2020	[redacted]	$ 252,900	Open	9/29/2020	[redacted]	$ 3,958,355
8/28/2020	I/C-CCA 2016	[redacted]	$ 926,200	Open	8/28/2020	[redacted]	$ 4,884,555
8/28/2020	I/C-CCA 2016	[redacted]	$ 336,600	Open	8/28/2020	[redacted]	$ 5,221,155
9/17/2020	I/C-CCA 2020	[redacted]	$ 256,950	Open	9/29/2020	[redacted]	$ 5,478,105
10/13/2020	I/C-CCA 2020	[redacted]	$ 173,500	Open	10/28/2020	[redacted]	$ 5,651,605
10/22/2020	I/C-CCA 2020	[redacted]	$ 173,200	Open	10/28/2020	[redacted]	$ 5,824,805
11/16/2020	I/C-CCA 2019	[redacted]	$ 49,939	Open	11/27/2020	[redacted]	$ 5,874,744
11/16/2020	I/C-CCA 2015	[redacted]	$ 123,461	Open	11/27/2020	[redacted]	$ 5,998,205
12/17/2020	I/C-CCA 2018	[redacted]	$ 175,100	Open	12/30/2020	[redacted]	$ 6,173,305
		[redacted]	$ 6,306,020			[redacted]	

Source: Staff Data Request 1.132, Attachment ExcelAPS21FA00088

As shown in the above exhibit, after reflecting beginning balance amounts for quantity and dollars (i.e., prior to 2020) the Company's total CCA inventory was 380,000 CO_2 emission allowances at a total value of $6,306,020. As shown under the Inventory Status column, all of the 2020 monthly emission allowances were open. Subsequent to the noted delivery dates, the "open quantity of 2020 emission allowances, which includes the prior periods) totaled 372,207 at a cost of $6,173,305. We tied the monthly emission allowance valuations to the Company's general ledger detail. No exceptions were noted.

As it relates to January 2021, the confidential response to Staff data request 1.132 included Attachment ExcelAPS21FA00089, but this attachment indicated there was no CCA emission allowance activity in January 2021 as the inventory report reflected the same ending 2020 CO_2 emission allowance inventory balances and amounts shown in the preceding exhibit. According to the response to Staff data request 1.137, retirements occur in October of each year in accordance with California regulations (see additional discussion below). The detail for the consumed/retired emission allowances in 2019 and 2020, including the quantities surrendered and the resulting journal entry, was provided in Staff data request 1.137. We tied the amounts to the general ledger. No exceptions were noted.

According to the response to Staff data request 1.135, APS relies on FERC's General Plant Instruction No. 21 as guidance with regard to the accounting for emission allowances as required by Title IV of the Clean Air Act. Specifically, General Plant Instruction No. 21 generally requires non-speculative emission allowances to be recorded at cost in FERC Account 158.1 and FERC Account 509 - Allowances is debited each month in order for the cost of carbon allowances to be remitted annually is charged to expense on a monthly basis based on each month's emissions.

In terms of the specific accounting treatment of its emission allowances, according to the response to Staff data request 1.134, upon recording each carbon emission allowance into inventory, the Company posts the following journal entry:

Dr: FERC Account 158 (CCA Inventory)

Cr: FERC Account 242 (Short-Term Liability)

To record each month's liability and expense, the Company posts the following journal entry:

Dr: FERC Account 509 (Carbon Allowances Expense)

Cr: FERC Account 242 (Current Carbon Allowance Obligation)

Cr: FERC Account 253 (Long Term Carbon Allowance Obligation)

APS stated that it determines the monthly obligation from selling power to the CAISO. The Company provided its applicable policies and procedures for accounting for emission allowances in a 17-page document titled "Back Office Reporting: California Carbon Accounting Level 3" in its response to Staff data request 1.134. This document applied to the accounting of emission allowances for the entire review period.

We asked APS what kinds of costs, other than emission allowance purchase costs, are included in emission allowance inventory. In response to Staff data request 1.135, the Company stated that it does not include any other costs in its emission allowance inventory nor does Company enter emission allowances into inventory that were generated by APS. In addition, the emission allowance purchases are unbundled and are entered into inventory at the transaction cost. With regard to how APS determines when emission allowances are considered to be consumed or retired, the Company stated that in November of each year, a portion of the allowances held are retired through the Compliance Instrument Tracking System Service ("CITSS"). This process is based on the requirements set forth by California Assembly Bill 32 from the California Global Warming Solutions Act of 2006 and the related rules, regulations and amendments.[84]

As for how emission allowance costs are recovered through the PSA, the Company stated that pursuant to the PSA POA, the recovery of mandated carbon emissions costs is allowed when it is economical to incur such costs.[85] Specifically, on page 1 of the PSA POA states the following:

> The PSA allows for the refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base cost of amount of ($0.000001) per kWh and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.
>
> APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so it not an economical choice for APS's Arizona ratepayers.

The ($0.000001) per kWh referenced in the passage above is the result of the following calculation:

Exhibit 4-64
Base Net Margins on the Sale of Emission Allowances

Description	Amount
2015 Net Gains from Sales of SO2 allowances	$ 25,181
2015 Test Year Native Load sales	27,030,686
Subtotal	$ 0.000932
Divided by 1,000	1,000
Base Net Margins on the Sale of Emission Allowances	$ 0.000001
Source: PSA Plan of Administration approved in Decision No. 76295	

The base net margins on the sale of emission allowances of ($0.000001) per kWh was effective as of August 19, 2017, pursuant to Decision No. 76295. On page 6 of the PSA POA, it states that the base net margins on the sale of emission allowances is generally expressed as a rate per kWh that reflects the net margins on the sales of emission allowances embedded in the base rates approved by the Commission in the Company's 2016 rate case in Docket No. E-01345A-16-0123.

In its response to Staff data request 1-136, the Company stated that it did not sell any emission allowances during the 2019, 2020 and January 2021 review period. Upon reviewing the

[84] Collectively known as the California Cap and Trade Program.
[85] See the response to Staff data request 1.135.

Company's monthly PSA filings[86] (specifically Schedules 2 and 3), we verified that the Company did not reflect any net margins on the sales of emission allowances for each month January 2019 through January 2021.[87]

Changes To Fuel, Purchased Power Procurement And Emission Allowance Procurement

Documentation related to the review of changes to fuel, purchased power procurement and emission allowance procurement during calendar years 2019, 2020 and January 2021 was requested in Staff data request 1.48 and Staff data request 1.49.

Specifically, Staff data request 1.48 asked the Company to list and describe all organizational changes to the Company's Fuel procurement, Fuel accounting, Purchased Power Procurement and Emission Allowance procurement and accounting during the review period. In response, APS stated that other than routine and immaterial refinements in the normal course of business, there were no changes related to Fuel procurement, Fuel accounting, Purchased Power procurement and Emission Allowance procurement during the review period.

Staff data request 1.49 requested information similar to Staff data request 1.48, although from a procedural versus organizational standpoint. In response to Staff data request 1.49, APS stated that other than routine and immaterial refinements in the normal course of business, there were no procedural, policy or accounting changes related to the Fuel, Fuel Transportation, Purchased Power and Emission Allowance during the review period.

External and Internal Audits

We requested that the Company provide a listing of any external audits conducted by or for APS during the 2019, 2020 and January 2021 review period that were related to fuel and power purchases, fuel transportation, emission allowances, replacement power, fuel inventory, plant operations and fuel and purchased power. In its response to Staff data request 1.106, the Company stated that it is not aware of any external audits conducted during the review period that related to the areas referenced above.

In addition, we requested that the Company provide a listing of any internal audits conducted by or for APS during the review period that were related to fuel and power purchases, fuel transportation, emission allowances, replacement power, fuel inventory, plant operations and fuel and purchased power. In response to Staff data request 1.105, APS provided a listing comprised of 14 internal audits, all of which were related to plant operations and were conducted at various points during 2019 and 2020 (there were no internal audit listed for January 2021). Of these 14 internal audits, we reviewed copies of nine of the related internal audit reports, which were provided in response to Staff data request 2.1.

The conclusions in the nine internal audit reports that were prepared by Audit Services Department ("ASD") were categorized as follows:

- Effective – Overall controls are designed and operating effectively with limited residual risk exposure to the Company.

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[86] APS's monthly PSA filings were provided in the Company's response to Staff data request 1.95.

[87] According to the response to Staff data request 1.137, APS does not sell emission allowances.

- Some Improvements Needed – Overall controls are designed and operating effectively with a moderate residual risk exposure to the Company. A few specific areas of control improvements were identified during the course of the audit.
- Significant Improvements Needed – A number of controls are designed and operating effectively; however, control exceptions were identified which pose a significant residual risk to the Company. Overall, there is a potential significant risk to the Company's operational objectives.
- Unsatisfactory – Control(s) evaluated are not adequate or effective in providing reasonable assurance that residual risk(s), which could pose a major impact to the Company's operational objectives, are being mitigated and/or a significant fraud was identified.

We reviewed the nine internal audit reports, each of which is summarized below:

1. Selective Catalytic Reduction ("SCR") Project Management Process Audit (report dated June 28, 2019)

The objective of this audit was to assess the effectiveness of the Company's process to manage and administer the installation of the SCR pollution control devices on Units 4 and 5 of Four Corners. For this internal audit, ASD did not report any findings and its overall conclusion was that the controls in place were effective.

2. Four Corners Power Plant Environmental Audit (report dated January 23, 2020)

The objective of this audit was to assess compliance with governmental regulations and Company policies and procedures at the Four Corners plant. For this internal audit, ASD reported five findings in the area of Spill Prevention Control and Countermeasure with its overall conclusion being that some improvements were needed. For each of ASD's five reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

3. Four Corners Power Plant Health and Safety Audit (report dated January 23, 2020)

The objective of this audit was to assess compliance with governmental regulations and Company policies and procedures at the Four Corners plant. For this internal audit, ASD reported nine findings and with its overall conclusion being that significant improvements were needed. For each of ASD's nine reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

4. Cholla Power Plant – Environmental, Health, and Safety Audit (report dated June 10, 2019)

The objective of this audit was to assess the Cholla plant's compliance with applicable governmental regulations, as well as Company policies and procedures. For this internal audit, ASD reported seven findings and with its overall conclusion being that some improvements were needed. For each of ASD's seven reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

5. Ocotillo Power Plant – Environmental, Health, and Safety Audit (report dated July 5, 2019)

The objective of this audit was to assess the Ocotillo plant's compliance with applicable governmental regulations, as well as Company policies and procedures. For this internal audit, ASD reported three findings and with its overall conclusion being that some improvements were needed. For each of ASD's three reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

6. Palo Verde Water Resources – Environmental, Health, and Safety Audit (report dated August 9, 2019)

The objective of this audit was to assess the Palo Verde Water Resource facility's compliance with applicable governmental regulations, as well as Company policies and procedures. For this internal audit, ASD reported three findings and with its overall conclusion being that some improvements were needed. For each of ASD's three reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

7. Yucca Power Plant – Environmental, Health, and Safety Audit (report dated October 23, 2020)

The objective of this audit was to assess the Yucca plant's compliance with applicable governmental regulations, as well as Company policies and procedures. For this internal audit, ASD reported one finding and with its overall conclusion being that some improvements were needed. For each of ASD's one reported finding, Company management proposed an action plan. For the management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

8. West Phoenix Power Plant – Environmental, Health, and Safety Audit (report dated October 23, 2020)

The objective of this audit was to assess the West Phoenix plant's compliance with applicable governmental regulations, as well as Company policies and procedures. For this internal audit, ASD reported two findings and with its overall conclusion being that some improvements were needed. For each of ASD's two reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

9. Fossil Training Program Audit (report dated October 9, 2020)

The objective of this audit was to assess the effectiveness of the Fossil Training Program and to ensure employees are properly qualified. For this internal audit, ASD reported eight findings and with its overall conclusion being that some improvements were needed. For each of ASD's eight reported findings, Company management proposed action plans. For each management action plan discussed, ASD concluded: "ASD has reviewed management's proposed action plan and believes that it appropriately mitigates the risk noted and it will be implemented in an appropriate time frame."

Conclusion

As noted above, for each of the nine internal audit reports we reviewed, ASD concluded that the control deficiencies it identified were appropriately mitigated by the action plans developed and implemented by APS management.

In addition to the internal audits discussed above, we asked APS whether it has conducted any internal audits of the processes and calculations associated with any of its PSA filings during calendar years 2019 and 2020 as well as January 2021.[88] In its response to Staff data request 1.107, the Company stated:

> APS has not conducted an internal audit of the processes and calculations associated with any of its PSA filings during calendar years 2019 and 2020 and January 2021. The process of completing the PSA filings is generally considered to be a low inherent risk, in part because there are Sarbanes-Oxley ("SOX") controls in place for fuel calculations and the preparation of the PSA filing. APS tests those SOX controls for design and operating effectiveness twice annually.

Based on the foregoing passage, we requested that APS identify the specific SOX controls that APS has for it fuel calculations and for the preparation of its PSA filings. In its response to Staff data request 2.4, the Company provided the following SOX controls:

[88] It should be noted that APS conducted an internal audit of its PSA filing and procedures in October 2018 pursuant to Recommendation III-2 from the prior fuel audit conducted by Schumaker & Company in 2017.

SOX Reference	SOX Control Description
FIN 11	The material inputs to the deferred fuel calculation are reviewed and traced back to the supporting schedules by the Accounting Manager. Additionally, a monthly PSA meeting is held with managers from various regulatory, operations, and accounting groups to discuss the deferred fuel calculation, current fuel costs, and pending rate orders that may impact the PSA.
CE7	The Energy Advisor performs reconciliations of data between in-scope systems. Specifically, for Physical Power deals, this includes the interfaces between systems used for trading, fuel allocation, and financial reporting. The Energy Advisor reconciles the data between the sources to ensure the data transfer is accurate and complete.
M&T C1	Transaction details are reconciled with counterparties through confirmations directly with the counterparty, or through clearing statements for transacctions done through a broker (this is only for power financial deals and carbon allowances). Confirmations are done through either hard copy format (physical deals) or electronically (financial deals).
M&T S1	Counterparty checkout: Physical and financial power and gas transactions settled for the month are verified with that counterparty.
FR1	On a monthly basis, the Accounting Manager reviews the Classification Validation and Deal Matching Reports to determine if there were any deals that are recorded in books that would normally not be considered appropriate. Any deals where the classification appears to not be appropriate, the Accounting Manager will investigate and, if necessary, the deal will be reclassified to the correct book.
EIM1	Weekly, EIM revenues and charges are validated by the EIM Settlements Energy Analyst using settlement statement data and invoices received from the CAISO. The Leader or Manager reviews the Analyst Checklist and approves any payables/receivable amounts.
Source: Staff Data Request 2.4	

The Company stated that these SOX controls are performed in support of (1) the fuel and purchased power calculations, and (2) PSA filings, and that such controls ensure the completeness, accuracy and validity of fuel and purchase power transactions from inception through the regulatory and regulatory reporting processes.[89]

We requested that APS provide the results of its testing of the SOX controls twice in each year 2019 and 2020 as well as in January 2021. In response to Staff data request 2.4, the Company stated that the controls are tested using methodologies that are designed to meet SOX requirements and that such testing is generally performed after mid-year and at year-end in order to ensure operating effectiveness for the entire year. For calendar years 2019 and 2020, the Company concluded that all the SOX controls reflected in the above table were operating effectively in each of the two testing periods. With regard to SOX testing performed in January 2021, APS stated that such testing had not been performed during that month as it was prior to the mid-year point in which the first of the two annual testing of these controls was performed.

Findings And Recommendations

Our findings and recommendations are summarized in Chapter 1.

[89] See the response to Staff data request 2.4.

Appendix A
Photographs of Cholla Plant
August 24, 2021 Onsite Visit

The photograph below is of the Cholla Plant:

The photograph below is of the coal pile at Cholla:

The photograph below is of the reclaim tunnel from the coal pile and conveyor belt at Cholla.

The photograph below shows the "coal dozer" at Cholla.

The photograph below shows the Unit 3 and 4 stacks at Cholla:

The photograph below shows the Cholla rail line and cooling supply:

The photograph below shows the crusher tower and coal offloading at Cholla Unit 1:

The photograph shows the Cholla Unit 1 stack and return canal to the lake:

Appendix B
Photographs of Four Corners Plant
August 25, 2021 Onsite Visit

The photograph below is of the Four Corners Plant:

The photograph below is of the Four Corners generator building and Units 4 and 5:

The photograph below is of the Four Corners lime silos:

The photograph below is of the Four Corners coal conveyor after the mechanical sampler drops coal into the surge bins:

The photograph below is of Four Corners main coal belt headed towards the silos:

The photograph below is of the Four Corners coal handling facility - comprised of 10 piles of coal inventory on mine property:

End of Report